Ontario

THE REPORT OF THE
Royal Commission on Electric Power Planning

Chairman: Arthur Porter

VOLUME 5

Economic Considerations in the Planning of Electric Power in Ontario

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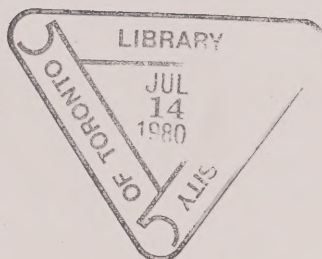
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Previous publications of the Royal Commission on Electric Power Planning

Shaping the Future. The first report by the Royal Commission on Electric Power Planning. Toronto, 1976

The Meetings in the North. Toronto, 1977

Outreach Guidebook. Toronto, 1976

Issue Paper 1: Nuclear Power in Ontario. Toronto, 1976

Issue Paper 2: The Demand for Electrical Power. Toronto, 1976

Issue Paper 3: Conventional and Alternate Generation Technology. Toronto, 1977

Issue Paper 4: Transmission and Distribution. Toronto, 1977

Issue Paper 5: Land Use. Toronto, 1977

Issue Paper 6: Financial and Economic Factors. Toronto, 1977

Issue Paper 7: The Total Electric Power System. Toronto, 1977

Issue Paper 8: The Decision-Making Framework and Public Participation. Toronto, 1977

Issue Paper 9: An Overview of the Major Issues. Toronto, 1977

A Race Against Time: Interim Report on Nuclear Power in Ontario. Toronto, 1978

Our Energy Options. Toronto, 1978

Report on the Need for Additional Bulk Power Facilities in Southwestern Ontario. Toronto, 1979

Report on the Need for Additional Bulk Power Facilities in Eastern Ontario. Toronto, 1979

List of Volumes

The Report of the Royal Commission on Electric Power Planning is comprised of the following volumes:

Volume 1: Concepts, Conclusions, and Recommendations

Volume 2: The Electric Power System in Ontario

Volume 3: Factors Affecting the Demand for Electricity in Ontario

Volume 4: Energy Supply and Technology for Ontario

Volume 5: Economic Considerations in the Planning of Electric Power in Ontario

Volume 6: Environmental and Health Implications of Electric Energy in Ontario

Volume 7: The Socio-Economic and Land-Use Impacts of Electric Power in Ontario

Volume 8: Decision-Making, Regulation, and Public Participation: A Framework for Electric Power Planning in Ontario for the 1980s

Volume 9: A Bibliography to the Report

Economic Considerations in the Planning of Electric Power in Ontario

Paul Burke

The Author

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Foreword

The Commission wishes to acknowledge the contributions to our Report made by the author of this volume. The enormity of the task as well as the skill and tenacity with which it was performed are testimony to the talents of Paul Burke. Our work would have been immeasurably more difficult without his assistance.

This volume, *Economic Considerations in the Planning of Electric Power in Ontario,* focuses on a key issue area raised by the public during the Commission's public hearings process. The analysis, conclusions, and recommendations reflect data received by the Commission in the form of public testimony and exhibits, consultants' reports, and independent research and analysis by the author. We have relied heavily on this work in formulating our own conclusions and recommendations in Volume 1. However, the views expressed in this volume are ultimately the responsibility of the author. This document is therefore best viewed as a background paper which attempts to draw together the detailed evidence and analysis available on this complex subject, in a fashion which will be of use to the general public as well as to the technical community.

The research and evolution of this document were directed and reviewed for the Commission by Philip A. Lapp and Peter G. Mueller.

Arthur Porter, Chairman.

Executive Summary

Ontario is almost entirely dependent on outside sources for fossil fuels. The loss of income that results from higher energy payments can be minimized basically in two ways: by reducing the use of "imported" fuels and by increasing net exports of goods and services. When conservation and inter-fuel substitution are cost-effective they offer an efficient and reliable way to reduce the province's energy deficit. Increasing net exports entails the element of risk that arises from penetrating new markets during a highly competitive period.

A transition strategy away from fossil fuels should balance the incremental unit energy cost of delivering and utilizing electricity from nuclear plants against the unit cost of energy saved by conservation measures or supplied by renewables, taking into account the load characteristics of the end use. The relative incremental unit energy costs that result from analysing Ontario's energy options on a uniform basis should be used as guidelines in the planning of a provincial energy policy. To implement those options in the long-run interest of the province, it will be necessary for the government to use its wide range of influence over market forces.

An adequate and relatively inexpensive supply of electricity is certainly one of the pre-conditions for the establishment of a balanced industrial development programme, but it will do little to foster new development by itself. Only for a few highly electricity-intensive industries is the price of electricity a significant factor in choosing the location of a production facility. Reliable service is a prerequisite for a wider range of companies, but this is a characteristic Ontario will continue to share with numerous other jurisdictions in Canada and the U.S. Government analysts now acknowledge that attractive electricity prices are of diminished importance in drawing industry. Ontario will be obliged to compete by marketing a combination of advantages, including reasonably priced electricity.

Much of Ontario Hydro's surplus capacity in the 1980s will consist of oil-fired units that will probably be in demand only for export in an emergency. Given the long lead times experienced by any electricity utility, Ontario's potential customers in New York and Michigan are already proceeding with their expansion plans for the late 1980s. Ontario Hydro is in a position to augment the medium-term capacity of these utilities but is unlikely to be able to substitute its capacity for theirs. Export sales will be predominantly of Hydro's coal-fired capacity, replacing the buyer's oil-fired thermal generation, particularly in the summer months.

The outlook for significant export sales of nuclear power in the 1990s, with their attendant benefits for the Ontario economy, is, at best, uncertain. The long lead time from the decision to build to the commissioning of a nuclear station increases the risk and the financing problems to the point where such a project may not be viable as a private venture designed to capitalize on a deterioration of electricity supply in the northeastern U.S. Advancing the in-service dates of Ontario Hydro stations by several years in order to sustain activity levels in the nuclear industry would involve considerably less financial risk.

Within the financial community there appears to be little doubt that, in the long run, the debt financing available to Ontario Hydro will be maximized if Hydro bonds continue to be guaranteed by the provincial government and the government retains its AAA rating. With the stretched-out expansion plan, capital availability now appears unlikely to be a constraint on Hydro planning in the 1980s. However, despite the capital availability surpluses that are expected in the 1980s, Hydro's expansion plans could still be vulnerable to financing problems. The major risk is that, in a period of slower economic growth and declining non-public sources of funds, the Ontario government will issue public debentures to finance its own deficit or other energy-related capital projects, thereby cutting into Hydro's borrowing. Also, Hydro's real costs could escalate faster than the rate of growth of the capital markets as activity in the energy sector heats up and concern over nuclear power leads to greater expenditures on safety systems. Finally, there remains an element of risk in borrowing in the U.S., because of the possibility that international capital markets will be destabilized by inadequate recycling of petrodollars.

The dramatic increase in fossil-fuel prices in the mid 1970s brought an end to a long era in which Ontario Hydro had experienced declining real increases in unit energy costs in serving both peak loads and base loads. Until the late 1980s, the electric power system will be in a transitional period in which nuclear plants will meet an increasing share of the total demand but marginal peak and off-peak loads will be served by fossil-fuelled stations with rising unit energy costs. As the nuclear:fossil generation mix approaches its target ratio around 1990, base-load generation costs are expected to stabilize in real

terms. Compared with rises in oil and natural gas prices, the escalation in base-load electricity costs will be modest. However, the unit cost of serving daily or seasonal peak loads will continue to escalate. If fossil-fuelled stations serve most of these loads, costs will rise to track coal prices. If some of the peak uses are supplied by nuclear stations, then costs will rise because of the expense of operating nuclear stations at lower and lower annual capacity factors. This divergence between incremental peak and base-load costs, that is, essentially, between the fossil and non-fossil components of the system, is a departure from historical trends that should be reflected in Hydro's rate design. A shift from power at accounting cost towards power at economic cost could make a significant difference to both the structure and the levels of electricity rates, and hence to future electricity demand. It is argued that the period of excess capacity in the 1980s should not delay the implementation of a more economically efficient marginal cost-based rate design that reflects clear long-run trends in the cost of supplying electric energy.

The starting point in weighing energy sector investments, whether they add to supply or lead to conservation, is some understanding of the degree of self-sufficiency, or security of supply, that is desired over the long term. As more demanding energy goals are set, the time horizon for a return on energy investments lengthens and the willingness to provide incentives for them increases. There is no "best" approach to encouraging the implementation of conservation and renewable energy programmes. Nonetheless, in order to plan alternative energy investments with the same long-term perspective Ontario Hydro uses for its generating stations, the province must accept a greater degree of government involvement in motivating investments. For instance, in order to promote industrial co-generation, a mini-utility backed with provincial debt capital may be needed to lead the way to maximum economic market penetration. Heat loss or building design standards will probably be needed to optimize home heat conservation measures.

The employment impact of capital expenditure in the energy sector has become a controversial point in the debate surrounding the selection of an energy strategy. Any preference for one method or the other of serving the same end use arises chiefly from differences in cost-effectiveness, as determined by a uniform comparison of the alternatives. Undertaking, as a top priority, energy-sector investments that either conserve energy or supply it at the lowest unit cost will give the energy consumer savings (relative to the available alternatives) to spend on other goods and services. These expenditures should result in the creation of more employment than equivalent expenditures on energy itself.

Introduction

The Scope of the Study

The Terms of Reference of the RCEPP and the issues raised by the public suggest two levels of planning of the electric power system in Ontario. One involves the principles Ontario Hydro applies when it adds to its generation and transmission system, as well as the consideration it gives to the impact of system expansion on a large number of factors that affect the interests of the people of Ontario. The second is concerned with the determination of the rate of system expansion, which in turn defines the role Hydro will play in the province's energy sector in the future. There are economic aspects to both areas of the inquiry, but the emphasis in this paper is on the broader issues of the second level of the planning process.

Ontario Hydro is a public enterprise responsible to the Government of Ontario and so receives fundamental policy directions from the government on broad questions of energy, environmental, financial, and economic policy. The allocation of the capital resources available to the provincial government to centralized electricity supply touches not only energy policy but also industrial development and fiscal policies.

Though Ontario Hydro's load forecast is still the main input to the system planning process, the level and the structure of electricity rates, two key variables influencing the demand for electricity, are effectively approved by the Province. In addition, the market price of the fuels with which electricity competes is regulated either by the provincial government or by the federal government in association with the provinces. Through its pricing policies, the Ontario government can influence the mix of electric and non-electric investments, including conservation, that are made in the energy sector.

In recent years the rate of growth of the electric power system has not, in fact, followed directly from Ontario Hydro's load forecast. System expansion has been constrained by limiting the borrowing undertaken on behalf of Hydro. Conversely, in a few specific instances, government decisions have led to expenditures on projects that were not consistent with meeting the demand for electricity at lowest feasible cost. The links between provincial planning and Hydro's long-range planning are complex.

The borrowing constraint imposed by the Ministry of Treasury and Economics early in 1976 heralded a new era in the relationship between the government and Ontario Hydro. Prior to 1976, it could be said, Hydro operated at arm's length from the government, that is, it determined its own financial needs. There was little competition for long-term public funds from other Ontario Crown corporations. As a result, as long as the combined capital needs of Hydro and the province did not exceed the capital resources deemed to be available, there was little interference by the government in Hydro planning. An arm's length approach was considered likely to improve Ontario Hydro's internal efficiency by more than enough to compensate for any overexpansion that might result. Indeed, any excess capacity was expected to be short-lived. As long as the real cost of power continued to decrease with increases in the system's capacity, lower real electricity rates would result, and these were likely to stimulate growth in demand without impinging on Hydro's ability to balance its books.

Since the mid 1970s, several factors have emerged that may alter the traditional relationship between Ontario Hydro and the provincial government in the direction of a more integrated approach to financial planning.

First, in a period of slow economic growth, an inertia in government programmes combined with a pressure for fiscal stimulus may conflict with Hydro's need for debt financing for its capacity expansion programme. The government might face a situation in which the demand for its services continued to outpace the growth in provincial output, while the supply of tax revenue and debt capital was growing no faster than the economy as a whole. The strain on the province's financial resources may require a clearer definition of provincial priorities than was needed in the past. At present, the sustainable borrowing potential of the province in public markets combined with the revenue Hydro expects to receive from rates, now acts as a constraint when Hydro develops an expansion programme. This upper limit on Hydro expenditures may not always be compatible with the province's need for funding.

Second, the increase in fossil-fuel prices since 1974 has created new investment opportunities in the energy sector, in Ontario, as well as in other provinces, that are in the long-run interests of the province. Some projects, such as those that have been undertaken by the Ontario Energy Corporation,

require more government financial backing than others, but it is quite possible that Hydro will be obliged in the future to share with other energy agencies the capital available to the province.

Third, for the next 10 years or so, Ontario Hydro will be in a transition phase in which the proportion of nuclear power in the generation mix will be increasing. Nonetheless, a real escalation in fossil-fuel costs and, perhaps, in nuclear construction costs could result in a period in which the real cost of Hydro's power may rise. In that case, excess capacity will become more of a liability than it has been in the past. As long as excess nuclear capacity could displace more costly coal-fired generation, the carrying costs of the excess capacity could be largely offset. Once Hydro's target nuclear/coal mix is reached and the displacement of coal capacity is no longer cost-justified, any overexpansion of nuclear capacity will become a financial risk to the province unless there is an assured electricity export market.

The impact of these three factors on the process of electric power planning in Ontario is the subject of much of this report.

Chapter 1 describes the economic implications for Ontario of escalating real fossil-fuel prices and outlines the alternatives open to the province to minimize the loss in economic well-being that is represented by payments to other provinces or countries for fuel shipments. The next three chapters analyse the major forces in the domain of the provincial government that will influence Ontario Hydro's capacity expansion programme until the turn of the century.

Chapter 2 focuses on projections of capital availability that were instrumental in shaping Hydro's expansion planning for the last few years. The reduction in Hydro's forecasted average annual load growth rate to 2000 from about 7 per cent to 4.5 per cent in the last four years, and the likelihood that load growth may be even slower than that, suggest that while capital availability will remain an overriding constraint on system expansion it may be less significant in future. The interdependence of many of the factors affecting load growth, capital availability, and government debt-financing requirements implies that this matter is not so clear-cut.

Chapter 3 looks at the role of prices in the preparation of Ontario Hydro's load forecast and the importance of the price sensitivity of demand for dynamic system planning. It discusses the implications for pricing policy of the transition phase to a system dominated by nuclear plants supplying most base loads and fossil-fuelled stations performing a peaking role, and examines the role of the rate of return in the setting of electricity rates.

Chapter 4 contains an analysis of three elements of provincial industrial policy that have been used as arguments for the construction of more generating capacity than is warranted by projected load growth in Ontario, or can be rationalized on the grounds of cost minimization. It examines the importance of Ontario Hydro's capital expenditure programme to the provincial economy and the electric supply industries, the role electricity plays in attracting industry to the province, and the potential for export sales of electricity.

Chapter 5 provides a fairly detailed analysis of the economics of co-generation, measures that reduce residential heat loss, and solar space and hot-water heating. The approach is to view these as examples of investments that reduce either the demand for centrally generated electricity or the need to substitute electricity for other fuels. Scenarios of market penetration combine a range of fuel-price forecasts and financing environments. One of the scenarios in each case assesses the market potential if public sector financing conditions applied and cost-effectiveness was assessed in relation to nuclear power at the appropriate load factor.

Chapter 6 has much in common with the themes of Chapter 4 but is placed after the chapter dealing with alternative energy investments because it compares, in general terms, the employment-creating potential of capital expenditures on centralized electricity generating facilities with that of capital expenditures on conservation and renewable sources of energy. The cost-effectiveness of energy investments when evaluated on a uniform basis emerges as a major determinant of economy-wide job creation.

The subject matter of this study has been strongly affected by the issues that were raised by the public in the course of the RCEPP's hearings and by the issue paper that was prepared by the RCEPP to stimulate discussion in the debate stage of the Commission's hearings. These issues are summarized in the following pages.

Issues Raised by the Public

Only seven days were devoted to financial and economic matters during the debate stage of the Commission's work, but economic and financial aspects of the broader issues before the Commission were frequently raised during the hearings. The Commission received considerable testimony regarding the place of electricity, conservation, and renewable energy in an Ontario energy strategy, and on the role of Ontario Hydro and of the government in provincial energy planning. However, the economic trade-offs and practical problems encountered in attempting to resolve these issues did not receive as much attention. A sampling of the principal themes presented to the RCEPP follows.

Energy Policy

In general, it was agreed among those appearing before the Commission that some kind of energy policy is necessary and that the Ministry of Energy should be the initiating agency. It was felt that Ontario Hydro should be regarded as just one of many supply agencies, and the demand for electricity as an inseparable part of the total energy demand:

> The complex [interactions] between energy supply and demand and a wide variety of social and economic issues . . . suggest that the kind of energy planning we in Ontario have had in the past is no longer appropriate − if, indeed, it ever was. A central feature of the approach, particularly as it applied (and applies) to electric power planning, is the assumption that the demand for energy is a quantity which one can extrapolate and attempt to anticipate with reference to a number of other trends like the assumed continuation of economic growth, but not something which one can legitimately plan in and of itself.[1]

The question of energy policy and energy planning was addressed most comprehensively by Energy Probe of Toronto in the first volume of its submission, in which it tackled the whole issue of planning and the methods involved. Energy Probe contended:

> Energy policy in Ontario suffers from an excessively narrow physical focus. This limits the purpose of planning activity to the development of technical measures which will maintain a satisfactory balance between the supply of and the demand for energy. However, the energy problem (measured by our ability to maintain the balance) is really only an intermediate problem. It is symbolic, and forms a part of a much broader issue involving resource use and socio-economic development in general. . . . The greatest failure of energy planning has been its unwillingness (or inability) to recognize and integrate issues of a social nature into policies.[2]

The position of economics in this energy policy was a matter of some importance to many of those making submissions. They felt that economics had been, and still was, an overriding preoccupation of all traditional energy-supply industries, including the government, but that it was time for a change:

> A revision of economic principles in energy policy is also sorely needed. One of the fundamental thrusts of economics is that the market price of a commodity reflects its social worth. Some might argue, then, that, even though energy demand is increasing at the expense of social and environmental quality, this is what society wants and [it] should therefore be accommodated. However, such an argument applies only if all of the externalities associated with energy production and use are included in the price of energy. Since this is by no means the case now, we can assume that demand is growing at a rate faster than it would if more sound economic and financial policies were endorsed and practiced.[3]

While Energy Probe and many others argued for the inclusion of more than just an economic base in the supply/demand equation, at least one individual was convinced of the superiority of "free market" demand and supply as a means of controlling electrical demand: ". . . the only rational framework with[in] which to come up with an optimal plan for the electric power system is based on financial and economic decision models".[4]

This intervener's solution was the use of the pricing mechanism to influence demand:

> The required solution to the energy problem is a very simple matter of economics. To ensure that there are no shortages price need only be set at a level where demand and supply are equal. Present methods of costing and pricing electricity are accounting fictions which do not reflect in any way demand and supply factors. Current electricity prices (on average) are well below economic costs. As a result, too much electricity is being consumed, growth in demand is much higher than warranted, and needless billions are being spent to increase Hydro's generating capacity.[5]

Other witnesses recommended a complete overhaul of the process by which energy policy is formulated and carried out, beginning with the role of government, and the Ministry of Energy in particular. The

Consumers' Association of Canada (Ontario), the Ontario Municipal Electric Association, and the Electrical and Electronic Manufacturers' Association of Canada (EEMAC) all presented submissions proposing preferred alternatives. Included in each of these models was greatly increased public participation during all phases of the process, from the establishment of the objectives of an overall energy policy to the actual siting of generating stations and other facilities.

Financing Ontario Hydro's Expansion

Few of the submissions tabled during the RCEPP's hearings dealt with the problem of financing the expansion of Ontario Hydro, perhaps because of the complexity of the subject, or because of a lack of knowledge concerning current methodology. Nonetheless, the Canadian Nuclear Association (CNA), the EEMAC, and an individual intervener addressed the problem, the last feeling that the days of low-cost energy were not over, and had, in fact, yet to be achieved:

> It is no secret that electricity supply and demand in Ontario has been increasing at about 7 per cent per year for the last 30 years. My submission envisages that a similar or even higher rate may continue for the next 40 years and I try to show not only why this is likely but also how it may be financed so that in 30 years or so the supply is costing only about half the present rate when calculated in constant dollars so that inflation is offset.[6]

Several interveners suggested that Ontario Hydro retire its entire debt. They submitted that this could be done in approximately 20 years, while maintaining a 7 per cent growth rate, by the expedient of increasing electricity rates and taxing oil. This would pay for the building of large nuclear power plants which would then produce the cheap energy base needed to continue the economic growth of the province and the country.

In contrast, the CNA and the EEMAC both felt that Ontario Hydro's borrowing was necessary, although the CNA spokesman expressed some reservations about the size of the debt: "I hope the present level of debt to equity would be a transient level, and that future rates would permit them to get to the proper ratio which will allow them to make a proper economic decision on plant selection."[7]

Ontario Hydro's capacity expansion programme is financed by rates and through debt issues. Acceptable rate levels were discussed by the EEMAC:

> The rate governing bodies of the government ... approve an ongoing program of such increases in electricity user rates as can be reasonably demonstrated by Ontario Hydro as being necessary to recover its total costs of system operations, maintenance, and approved capacity expansion, and earn an acceptable rate of return on its net assets over time.[8]

In addition to this, the EEMAC stated:

> We submit that Ontario Hydro be *unrestricted* as to the capital markets in which it may operate and in the types and terms to maturity of its issues. Hydro should be permitted to source and structure its debt portfolio in such a way as to optimize capital availability, amortization flexibility, average cost of borrowed funds, foreign exchange exposure, the matching of receipts and expenditures.[9]

Due to the large amount of foreign borrowing that appears to be necessary to finance energy projects in the next several years, and the difficulties that would be involved in raising this capital if projects bunched together, the EEMAC suggested that "an informal clearing-house of financial plans through the Bank of Canada might well be a useful exercise for all concerned".[10] This suggestion met with some scepticism, because other participants felt that federal and provincial authorities were fundamentally unable to co-operate on any subject for any reason.

Ontario Hydro's Impact on the Ontario Economy

Despite protestations to the contrary from Ontario Hydro, almost all of those submitting testimony felt that Hydro's building projects have a major direct and indirect effect on the economy and people of Ontario. The EEMAC said: "The planning, construction and operation of expanded or new generating plants and related facilities by Ontario Hydro provide heavy impact on economic growth locally, provincially, and to a lesser extent, nationally."[11]

There was little doubt regarding the local impact of Ontario Hydro construction projects on the surrounding towns and townships following evidence from the communities near the Darlington site and Bruce Nuclear Complex.

Many submissions suggested that it was not desirable to use Ontario Hydro projects as an economic development tool because of the temporary nature of the stimulus to the local economy. On the other

hand, some participants felt that it could be justified, to provide work during times of high unemployment, or to sustain the viability of the sole manufacturer of a particular type of equipment. The EEMAC, however, expressed another view:

> The long lead times associated with the construction of major power generation and transmission facilities would appear to make the concept of using such projects as a contra-cyclical economic tool quite impractical. Most governments have considerable difficulty anticipating directions in the level of economic activity projected six months to one year hence.[12]

A major study commissioned by the Ministry of Industry and Tourism on the use of nuclear generating stations to produce electricity for export was also presented. The idea of dedicating generating stations to the production of electricity for export is not new, but the study was described by the Ministry as an effort to ascertain whether the idea had economic viability. The rationale for this was stated as follows:

> Whereas we now export uranium in a semi-processed form, electricity can be considered to be a product which has large added value and is essentially uranium exported in a highly upgraded form. Electricity is in essence a manufactured product, very little different from any other manufactured product, except perhaps that it is produced in capital intensive installations with relatively low permanent manpower requirements.[13]

The Ministry also stated:

> As noted in the submissions we have made, the electrical industry, the heavy machine industry and the nuclear industry all represent areas in this province that could respond to additional business, that could create additional jobs, and so we, for that reason, felt that this was one of a number of important steps to be reviewed.[14]

The CNA also made a submission supporting the export of nuclear power:

> In economic terms the construction and operation of such stations would have all the advantages of similar stations constructed for domestic purposes. In financial terms these stations would have the additional benefit of earning revenue in U.S. dollars, thus making a material contribution to the Ontario and Canadian balance of payments. Whatever borrowing is necessary to finance the plants could be readily undertaken. Since it will be repaid by offshore earnings, the borrowing is of an entirely different character to that made for purposes of domestic expenditure.[15]

However, while the Ministry and the CNA may have felt that the idea was a good one, in general the feelings expressed in other submissions during the hearings were negative. The agricultural community was definitely against the export of power, suggesting that this would mean additional transmission lines, which would undoubtedly cross valuable farmland. Other interest groups and individuals were opposed not only to the dedication of generating stations to the production of power for export, but to any idea of exporting firm power. In their opinion, the export of firm electric power would increase the demand for power rather than decreasing it — which they would rather see.

The Economics of Alternative Energy Options

While many interest groups and individuals were in favour of conservation and the development of renewable energy sources, and certainly felt that these "soft" energy paths were preferable to "hard" energy paths, little substantive analysis was presented to prove the point. The major studies in this area were tabled by Energy Probe of Toronto and the Sierra Club of Ontario. The majority of the submissions appeared to rely on studies done in the United States on the impact of conservation and on the time frame for the introduction of renewables.

One group stressed two advantages of conservation:

> Conservation, first of all, buys time: time to engage in a reasoned discussion of our priorities without being harassed by pressure to commit ourselves to long-term energy supply strategies, under threat of shortages ten or twenty years down the road.

> Second, it buys economic flexibility. We have already seen that relatively small increments of conservation may permit the deferral of considerable capital investment.[16]

The Canadian Coalition for Nuclear Responsibility stated the same view in a rather more forceful way:

> That is to say, if projected increases in demand were to be accommodated through a conservation program rather than increased generation capacity, less capital would be required to maintain nearly similar consumption habits. By the same token, less investment capital would have to be diverted from other sectors of the economy, such as social service and health care programs, and from private concerns such as small businesses.[17]

The EEMAC declared itself in favour of government-assisted loans to help in the conversion to more efficient electrical machinery:

> If a financing scheme is introduced by a level of government to assist consumers in converting to a higher efficiency electrical machinery, then the local utility bill could be used as a vehicle for collecting the repayments of such loans. However, the electric utility should not be encumbered with the responsibility for providing the capital funds needed to finance such programs, since such costs may not be properly allocated to the cost of providing power.[18]

A number of groups and individuals felt that Ontario Hydro could feasibly move into the area of solar panel installation, in the same way that it began installing water heaters.

While all who made submissions were in favour of renewable energy sources over the long term, there was no unanimity about the shorter term. Witnesses ranged from those who felt that immediate implementation of solar space heating was feasible and would lead to an all-renewable-energy supply picture by 2025, to those who could see only a very small amount of the energy demand being filled by renewables in that time frame.

Again, the organization with the most comprehensive and detailed evidence was Energy Probe of Toronto. It presented an explicit scenario which, in the main, implied that it was not the technology that was lacking but the political will. This point of view was also stated by other organizations and individuals:

> The choice of a renewable energy future for Ontario is less a matter of research and developing new technologies [than] of developing the political will to implement policies which will encourage the application of technologies which exist now.[19]

> It is generally recognized that large-scale applications of solar heating, wind generation, heat pumps, and wood-burning systems are already competitive on a life-cycle cost basis compared to the alternative conventional option in many areas of the country. . . . Further, it is clear that other major applications such as methanol, energy plantations, and photovoltaics will reach economic viability in the 1980s.[20]

> Too often I hear people say, "We'll have to depend on solar energy eventually, but it's at least 20 years away, so meanwhile we'll have to depend on nuclear energy." When enough people say that, and particularly the decision-makers, then it is a self-fulfilling prophecy.[21]

Against such optimistic views of the future of renewables must be set the views of business organizations such as the EEMAC, the CNA, and the CMA and some individuals, all of which felt that, while there is a place and a time for renewables, it is not nearly as large or as imminent as its proponents think. Economics would dictate the introduction of the renewable technologies. The economics were not favourable and would not be for quite some time:

> Economic efficiency precludes the use of renewable resources when non-renewable ones are far cheaper. It precludes the banning of energy growth when consumers are willing to pay the full costs of that growth. Energy conservation is not a philosophical issue; it is a hard-nosed matter of dollars and cents.[22]

> Much attention is presently focused on research and development of alternate renewable technologies such as solar energy, biomass, wind power and "watts from waste". . . . These technologies are mostly still in the research and development stages, while none has yet grown past the pilot plant or small-scale stage. During the next several decades none is likely to become available as a commercial-scale operating scheme to meet or displace a significant fraction of the overall electrical energy demand in Ontario.[23]

Perhaps more than in any other part of the RCEPP's hearings, the submissions in the economics area lacked depth and specific detail. Many of the points quoted above were made in passing, in connection with other topics. The hearings may have revealed that the economics of energy are even less well understood than the technology of nuclear power.

The RCEPP Issue Paper

In March 1977, the RCEPP published an issue paper entitled "Financial and Economic Factors in Electric Power Planning". It summarized questions that were raised during the information-stage hearings of the Commission and discussed in submissions to the Commission. In addition, it put forward for debate matters that were of interest to the Ontario Energy Board and the Select Committee of the Legislature on Hydro Affairs. At the outset, the issue paper stated:

> At the most fundamental level, a major responsibility of the Commission is to explore the potential

roles of Ontario Hydro as a public corporation, combining the responsibilities of a delivery agency of government with the objectives of an energy Corporation in competition for resources with other public and private enterprises.[24]

The role Ontario Hydro plays in the province's energy and industrial strategies is largely determined by the Ontario government's policies regarding the utility's two sources of funds: debt financing guaranteed by the province and rate levels and structures approved by the province. In this regard, the issue paper asked:

To what extent ought Ontario Hydro to remain in its present financial relationship to the government? What would be the relative costs and benefits of considering the provision of electricity as a public service of the same type as the provision of schools, hospitals, and roads?[25]

What would be the consequence of capital availability becoming the starting point of planning the electric power system?[26]

Can Ontario Hydro construction projects be used as a contra-cyclical economic tool? Should they be?[27]

What are the potential impacts on other borrowers of large demands by Ontario Hydro? For example, would those demands restrict the capital available for alternate energy technology and/or conservation investments?[28]

Should differential rates be offered to certain customers to further specific goals? If so, what subsidies are implied?[29]

In order to formulate broader provincial energy policy goals, criteria are required for assessing the merits of additional electricity generating capacity as against other indigenous energy investment opportunities. The issue paper noted:

As the total energy supply situation in Ontario becomes more critical, two issues worth discussing are the degree to which alternative suppliers of electricity ought to be encouraged and the extent to which Ontario Hydro should discourage electricity usage and/or promote uses of other forms of energy.[30]

Specifically, it asked:

What conditions would encourage other industrial customers of Ontario Hydro to invest in generating equipment. What supportive policies would encourage such co-generation schemes?[31]

On a province-wide scale, what are the costs and benefits of investment in electrical energy-saving equipment as opposed to electrical energy supply?[32]

The impact on the Ontario economy of Ontario Hydro's capital expenditure programme is significant. Here, the issue paper was concerned with the consequences for employment in the supply industries and regionally of differing rates and types of capacity growth. It suggested that "a more comprehensive overview of the consequences of reduced electricity growth rates would be useful".[33]

It was suggested that the implications of reduced growth in system capacity for employment, economic growth, and investment in conservation options in the province should be investigated.

Adjusting to Energy Price Increases – the Perspective of a Consuming Province

Many of the economic issues that arise in planning the electric power system in Ontario for the 1980s and beyond concern the role that electricity, and in particular nuclear power, may play in the adjustment of the energy sector and the economy as a whole to an era of expensive fossil fuels. Ontario is almost entirely dependent on other regions of Canada and the world for its fossil-fuel supply. Since 1973, the rapid escalation of oil and natural gas prices has doubled the share of the Ontario gross provincial product (GPP) that leaves the province in the form of payment for these critical fuels.

Basically, there are two things Ontario can do to compensate for the loss in real income resulting from the growing energy deficit: reduce its use of imported fuels (in the sense of fuels purchased outside the province) and increase its net exports of goods and services. Both influence the desired growth path and nuclear:fossil generation mix of the electric power system in Ontario.

The first of these methods lies at the heart of Ontario's energy policy. It will involve assessing the economic attractiveness of electricity as a substitute for fossil fuels in the light of the enhanced feasibility of conservation measures and renewable energy sources. The impact of the second method on electric power planning will be less direct. The reliability and competitiveness of electricity, the potential for electricity exports, and the economic impact of Ontario Hydro's capacity expansion programme are all possible elements of an industrial strategy for the province. The weight assigned to these policy options will be reflected in the allocation of the provincial government's capital resources and in the extent to which pricing policies, and other financial incentives, act to motivate the private sector to respond to the long-term trend in energy costs.

This chapter deals in general terms with the impact of high fossil-fuel prices on the Ontario economy and takes an economic approach to the assessment of Ontario's options. To begin with, however, the premise underlying the chapter will be explained. It is that the fossil-fuel prices facing Ontario will not only maintain their real 1979 price but could double or triple in constant dollar terms before 2000. The focus is on oil, because oil sets the pace for the pricing of its close substitutes. Because of their poor record of accuracy since 1973, projections of Canadian and world oil supply and demand are suspect. Nonetheless, some basis for planning is needed. What follows is based on an assessment of published materials.

The Outlook for Oil Prices

It is currently federal government policy to equalize the price of oil across Canada. Ontario's payments for oil will depend on the speed with which the domestic price moves towards the international level and the escalation of the international oil price itself. As long as Canada is a net importer of oil there will be a strong economic incentive to remove the subsidy that encourages the consumption of oil from members of the Organization of Petroleum Exporting Countries (OPEC).

Canada became a net importer of oil in 1975. Its net exports of crude oil peaked in 1973, at 275 thousand barrels per day equivalent to 19 per cent of that year's domestic requirements.

By 1976, Canada was dependent on OPEC oil for 18 per cent of its requirements. The 1978 National Energy Board (NEB) report "Canadian Oil Supply and Requirements" projects that in 1985 37 per cent of domestic requirements may be met by imported oil. The NEB suggests little change in that dependency ratio over the decade to 1995 despite the completion of an additional 500 thousand barrels per day of oil sands production capacity. The shortfall projected for 1995, 900 thousand barrels per day, could be eliminated if the production of another six oil sands plants was available. The implied rate of construction of oil sands plants may not be feasible in the light of skilled labour and equipment constraints and environmental considerations. The contribution of offshore or frontier finds may be delayed considerably by lead times of the order of 10 years before full-scale production is attained.

In the NEB base case, Canadian oil production will be at a minimum in 1985-6, at about two-thirds of the present output level. It will grow slowly thereafter, so that indigenous sources are projected to be adequate to meet demand west of the Ottawa valley until the mid to late 1990s. The region east of Montreal will continue to rely on imported crude. The main threat to the oil balance west of the Ottawa valley is the possibility that imports to the eastern half of the country could be constrained by tight

international market conditions, which could lead in turn to a reallocation of domestic oil supplies. Inevitably, developments in the world oil supply/demand balance will set the pace for the transition away from oil, both for Canada, as a whole, and for Ontario. The world oil outlook and the expectations for the international price have evolved in several distinct stages since the oil crisis of 1973.

Studies prepared just after the OPEC price increases of late 1973 (e.g., "Energy Prospects to 1985", published in 1974 by the Organization for Economic Co-operation and Development (OECD)) predicted that rapid increases in western world oil supplies and the substitution of other fuels for oil, combined with a sharp reduction in consumption growth rates, would lead to a drop in world demand for OPEC output. The adjustment by oil-importing countries was expected to lead to the collapse of the cartel, and of its price, by the late 1970s.

The second round of investigation, benefiting from the experience of the recession in the industrialized world in 1974-5, was much more cautious about the ability of OECD countries to adapt to higher international energy prices (notably studies published in 1977 by the Central Intelligence Agency,[1] the Workshop on Alternative Energy Strategies,[2] and the OECD[3]). Long lead times in energy projects, limitations to the speed with which inter-fuel substitution could take place due to the existing stocks of energy-consuming capital, and the slow movement to world prices in North America were identified as factors militating against a rapid reduction in OECD demand for OPEC production. In general, the impact of conservation was quantified as a reduction in the ratio of energy to GDP growth, and the estimates appeared to be realistic. However, the GDP growth forecasts themselves were still based on trend extrapolations of the strong expansion of the 1960s and early 1970s. On the supply side, it was assumed that OPEC production would grow to the maximum extent feasible to accommodate world demand.

Even so, there was mounting evidence that by the mid 1980s there could be excess demand for OPEC oil despite conservation efforts. The timing was such that significant new non-OPEC supplies might not yet be on stream. In 1977, a pending oil crunch, probably taking the form of further drastic price rises in the mid 1980s, prompted the International Energy Agency (IEA) member countries to agree to oil-import targets for 1985 that would be below OPEC's expected production capacity.

The concern about an oil crisis in the mid 1980s was relieved temporarily in 1978. Long-term economic growth projections for OECD countries (which largely determined the predictions concerning the demand for energy given in the studies cited above) were revised downwards by an average of about 1 per cent in keeping with the economic climate predicted for the 1980s. The intersection of world demand with OPEC production capacity might have been extended as much as 10 years by a 1 per cent reduction in the average annual growth rate of world demand for OPEC oil. However, the events in the Middle East since late 1978 have combined to depress the supply side of the oil equation as well.

The revolution in Iran and socio-economic problems in other OPEC nations have highlighted the difficulty of productively absorbing the foreign exchange earned from oil exports. Oil producers have concluded that rushing the extraction of their non-renewable resources will over-accelerate the pace of their economic development. The sensitivity of the spot market price for oil to the tightness of the world oil market, revealed by Iran's production slow-down, confirmed the merits of keeping production targets to the desired rates that had been announced several years previously. The difference between Saudi Arabia's desired production rate of 8.5 million barrels per day and the range of 15-20 million barrels per day that had been assumed in the 1977 studies cited above is equivalent to about 15 per cent of the world demand for OPEC oil in 1985. The decision to exploit this leverage implies a period of upward pressure on world oil prices that could probably be broken in the short term only by a serious world recession. Ultimately, the limit on oil-price escalation is the level at which sufficient alternatives come on stream, on both the supply side and the conservation side, to reduce the dependence of oil-importing countries on OPEC production. The mid-range of the U.S. Department of Energy's scenarios for world oil prices in 2000 (as of the third quarter, 1979) is $35-$40 per barrel expressed in constant 1978 U.S. dollars. That is about three times the Canadian domestic price in 1979. The adjustment process is only just beginning.

The Macro-Economic Impact

About three-quarters of Ontario's secondary energy[4] consumption is in the form of oil and natural gas purchased from western Canada. With the doubling in constant-dollar oil and natural gas prices since 1973, payments to the producing provinces have risen from the equivalent of 2.1 per cent of GPP in

1973 to 4.9 per cent in 1978. The large oil and gas price increases to come will further increase the transfer of income from the province and contribute to a general redistribution of income in Canada from fossil-fuel consumers to producers. To begin with, the new wealth of the producing provinces will attract job-seekers and service industries, but eventually their growing markets and more secure energy supplies could be the drawing card for manufacturing firms. High fuel prices also have the effect of diverting capital that would normally have been invested in industries in central Canada to the producing provinces, to finance energy projects.

There would be no loss of stimulus to aggregate demand in Ontario if the income Ontario consumers transfer to fuel producers via payments for oil and gas were returned to the province in the form of purchases of goods and services made in Ontario (i.e., if payments for oil and gas were "recycled" in their entirety). Ontario industries would have at hand a new market to replace the diminished demand within the province. The number of jobs in Ontario would not be reduced, though the real income earned per employee would be lower than it would have been without the fuel price increases.

In practice, however, the vast majority of oil and gas revenues are spent locally, in the producing provinces. They are directed towards reducing the tax burden of citizens or to building up local infrastructure and social services. The recycling that results from this spending pattern is probably only proportional to the traditional share that goods bought from Ontario have formed of total expenditures. Another portion of the oil and gas revenues is saved in accounts such as the Alberta Heritage Trust Fund and is not returned to the income stream.

Whether or not fuel payments are completely recycled, Ontario will experience a loss in real income each time energy prices increase. Failure to counterbalance the reduced provincial demand for the output of Ontario-based industries with a net increase in exports (i.e., external demand) will further exacerbate the adjustment process. The additional benefits of the economic multiplier, that is, the indirect and induced effects of industrial production, would be lost to the province.

To the extent that the degree of recycling rises through national compromises surrounding future oil and gas price increases, Ontario will be spared the search for the new export sales needed to offset the increased cost of fuel. Strong competition for export markets can be expected, because all industrial economies face a similar recycling problem. Some countries that have already adjusted to higher energy prices have more efficient production processes that are not as sensitive to the increase in energy costs. These countries will have a temporary edge in international markets until the more energy-wasteful economies have exploited their remaining conservation potential.

Recapturing the multiplier effects of the income transferred to producers is one aspect of the adjustment to higher fossil-fuel prices. The other, as noted, is reducing the quantity of fossil fuels imported in the first place. This can be accomplished either by substituting indigenous sources of energy for fossil fuels or by reducing the energy-intensity of the economy as a whole. Both substitution and conservation are triggered by the action of market forces on individuals' or firms' consumption decisions; Ontario's options are discussed in the next section. However, the restructuring of the overall economy that is entailed is not likely to take place without a cost in terms of potential output.

It is a complex matter to trace the dynamics of the response of an economy to higher real fuel prices. In industrial processes, a firm may reduce its costs either by using less energy-consuming machinery and equipment (when energy and capital are "complements") or by making additional investments to improve the efficiency with which it uses energy (when energy and capital are "substitutes"). In order to reduce the cost of its inputs, a firm could decide either to employ less energy-consuming machinery and equipment or to make additional investments to improve the efficiency with which energy is utilized. Either way, higher costs of production will likely be passed on to consumers, whose demand will shift, to some extent, away from more energy-intensive products. These effects will tend to lower the average energy-intensity of the industrial sector. Similarly, consumers will attempt to recapture the share of their budget that is lost due to higher fuel expenditures by changing their consumption habits and investing in energy-saving equipment. On net, the allocation of capital to improving the utilization of energy by industry and households will probably detract from the historical rate of investment in expanding the production of final goods.

Jorgansen and Hudson, American macro-economic modellers of the impact of energy price increases, conclude:

> The substitution of labor, capital and nonenergy goods and services for energy input into production is not perfect; some output is lost as a result of the restructuring. In other words additional labor and

other inputs can help to compensate for less energy input but some reduction in net output is still probable. Also, additional labor and other inputs used to replace energy must be obtained from other uses, thus reducing the total volume of potential output.[5]

When real price increases motivate cost-effective measures to reduce fuel imports, the income that would have been transferred to fuel producers is retained within the consuming province. This ensures that the indirect and induced effects of spending that income also accrue to the consuming province. Reducing fuel imports keeps the negative economic impact of higher energy prices to a minimum by effectively eliminating the losses associated with less than complete recycling.

Weighing Ontario's Options

Policies that reduce the import of fossil fuels or stimulate the net export of goods and services would both help to offset the rising deficit in Ontario's energy account (see Figures 1.1 and 1.2). Economic principles can be used to help delineate the appropriate balance between the two policies. However, the response of governments to the risks of long-term dependence on other jurisdictions for such an essential commodity as energy is difficult to predict. Vulnerability to price increases will likely favour the energy-sector side of a transition strategy.

If energy were perceived to be a commodity much like any other, increasing Ontario's self-reliance or security of supply would not be pursued beyond a level consistent with economic efficiency criteria. Economic theory suggests that, if a region does not have a comparative advantage in producing a commodity it wishes to consume, then it should have no qualms about importing it and paying for its imports with the proceeds from sales of other goods and services in which it does have an advantage. For example, when the marginal cost[6] of utilizing electricity in the end uses in which it is technically feasible to do so, or the cost of saving a unit of conventional energy becomes greater than the price of imported fossil fuels, additional investments in electricity supply or conservation would no longer be worth while. At this point, an economy would be better off to develop its ability to pay for its purchases. Of course, if they are to help offset the energy import bill, the additional goods and services need to be competitive, that is, capable of substituting for other imports or augmenting exports.

A goal of minimizing the vulnerability of the Ontario economy to energy supply and price fluctuations would require that the length of the investment planning horizon in the energy sector be extended. It could involve undertaking energy investments that require a lower rate of return or, equivalently, have a longer pay-back period than normal business or perhaps even than government practice. This need not lead to an "inefficient" allocation of resources, because the interdependence of energy consumers in an industrialized society may be difficult to reflect in the price of energy. This becomes apparent in extreme cases where energy shortages may create more serious bottlenecks for the entire economy than shortages of almost any other input. Market prices may undervalue the long-term benefits to society of energy investments, compared with investment projects in general.

An alternative policy, not mentioned thus far because it would do little to reduce Ontario's payments for energy, is to focus on security of supply directly. The province could consider financial participation in fossil-fuel supply systems (i.e., pipelines and oil sands plants) outside Ontario. Limited equity involvement in a project that is in Ontario's interest (e.g., Syncrude) is well and good when that involvement makes the critical difference between the project proceeding and being cancelled. Indeed, the extra orders for Ontario's industrial goods may more than offset the drain on the province's resources. However, as the price of oil in Canada moves to world levels, most viable projects will probably be undertaken on their own merits. Ontario may gain little, while seriously stretching the limited capital resources available to the provincial government. One of the benefits of paying world prices for oil and natural gas would be to direct Ontario energy policy towards investments within the province.

The two avenues by which Ontario may most readily reduce its net energy payments are inter-fuel substitution and conservation. The indigenous sources that could displace fossil-fuel imports are hydraulic and nuclear electricity and renewable forms such as biomass and solar. There appears to be little potential to increase fossil-fuel production in Ontario. The prospects for the export of nuclear power to the U.S. are limited before 1990 and unclear thereafter (see Chapter 4). Though the conversion of coal from the U.S. and western Canada to electricity for the purpose of reducing the use of oil may shift consumption patterns to a longer-term fuel source, it is unlikely to reduce the province's bill for imported energy. In fact, moderating the use of on-peak electricity generated by fossil fuels through load-management techniques or time-of-use pricing may be one of the better conservation measures open to the province.

The appropriate mix of electricity, renewable energy, and conservation cannot be generalized but needs instead to be optimized separately for each energy end use. When inter-fuel substitution takes place, not only the cost of supplying the energy but also the cost of converting or modifying the energy-consuming capital good is relevant in the benefit-cost analysis. Since conservation measures may cost-effectively increase the efficiency with which either the energy substitute or the original fuel is consumed, an analysis of inter-fuel substitution should also assess the role conservation can play.

Electricity has the technical potential to substitute for fossil fuels in three large classes of energy end use: transportation, space heating, and industrial process heat. The technical potential is, however, severely limited by economic considerations either on the supply or the utilization side. This paper will only be able to indicate a few of these factors in the course of demonstrating the value of total-system studies of individual end uses. A fuller discussion of the potential to substitute electricity for fossil fuels is to be found in Volume 3 of this Report.

Because the cost of supplying electricity, and in particular nuclear-generated electricity, varies with the load characteristics of the prospective end use, some substitutions are more feasible than others. For example, industrial process steam and direct heat applications could be year-round base loads, readily, though not necessarily cost-effectively, served by an increase in nuclear capacity.[7] Electric space heating, on the other hand, is a seasonal load that may, in practice, be met by coal-fired units for some time to come. Appendix A estimates the long-run incremental cost (see note 6) of meeting loads over a range of annual load factors. It finds that the unit cost of electricity for space heating, whether coal-fired or nuclear, is roughly twice that of industrial base loads.

Space heating provides a good example of an end use in which the merits of fuel substitution, renewable energy, and conservation must be carefully weighed. Much of Chapter 5 is devoted to analysing residential space heating from the perspective of incremental costs. For new, non-apartment dwellings, it is estimated that insulation levels in electrically heated homes well in excess of the minimum standards of the Ontario Building Code would be cost-justified when assessed on the same basis that is used to determine the unit cost of incremental electricity supplies. Improvements in home design not only reduce the need for electricity, but may also threaten the viability of the foremost renewable contender, solar collectors. In the experience gained with Saskatchewan House, a demonstration project of the Saskatchewan Research Council, optimal insulation, infiltration control, and passive solar design appear to make the addition of active solar space heating uneconomic. The role for electricity could be restricted to small quantities of off-peak energy for back-up.

For both space heating and industrial process heat, the cost of actually utilizing the electricity instead of a fossil fuel does not figure prominently in the economic choice. The long-run relative fuel costs are the key factor. In the transportation sector, the reverse is true. It is the capital required to transform transportation systems so that they can utilize electricity that will limit electricity's potential to substitute for oil, not the oil/electricity price differential.

In urban public transit, the mode most conducive to electrification, the capital expenditure on additional electric generating capacity is just the tip of the iceberg. The Urban Transit Development Corporation's 1976 submission to the Commission, entitled "Moving into an Energy Efficient Society", promoted a view of urban transit in 1990 that was called "Scenario 45". The study estimated the additional front-end cost of increasing the proportion of urban trips made by mass transit in Ontario in 1990 to 45 per cent from 25 per cent at about $3.3 billion (1976 dollars). The additional peak generating capacity required was estimated to be about 300 MW. Its capital cost would be about one-tenth of the capital cost of the transit system. If this ratio is at all indicative, the substitution of electricity for oil in mass transportation will depend much more on overcoming the institutional hurdles to financing the transit facilities than on the relative cost of electricity and oil.

For modes other than urban mass transit, a substitute liquid fuel, eventually perhaps made from biomass, may compete favourably with electricity as a substitute for oil. The relative price of electricity and substitutes would probably be a small element in the total system costs of switching to electrical vehicles rather than adapting the existing transportation infrastructure to another liquid fuel.

The major classes of end uses in which electricity could technically substitute for fossil fuels have not yet been comprehensively and uniformly analysed in Ontario. The task involves a comparison of the total incremental cost of delivering a unit of electric power to the end-user with the unit cost of alternative measures to serve or reduce the requirements of that end use. Such comparisons provide a more

appropriate way to determine the role of nuclear power in Ontario than electricity system cost comparisons of coal-fired and nuclear stations. The cost results discovered on the basis of uniform financing assumptions should point the way for the development of strategies to implement measures that are in the long-run interest of the province, whether they be electric or non-electric.

The provincial government has an important role to play in facilitating the adjustment away from imported fuels. The market-place for energy is highly regulated, usually for the purpose of keeping energy prices as low as possible. However, the province's ability to influence the determination of interprovincially traded oil and gas prices and of Ontario Hydro's electricity rates, combined with its ability to design tax incentives that could alter energy-consumption habits and its access to low-interest long-term debt capital, means that it has the tools for creating the market forces needed to implement longer-term energy policies. Postponing the adjustment to higher fossil-fuel prices increases the likelihood of rationing and mandatory measures farther down the road. For long-term energy planning purposes, a firm timetable and a clear goal for future energy prices may be nearly as effective as an overnight jump in prices. Energy investments could be motivated without the risk that dramatic price increases might destabilize the economy.

Summary

The energy crisis has evolved into a long period of adjustment to higher energy prices. Current indications are that Canada is likely to remain a net importer of oil until at least the mid 1990s and that during this period the OPEC nations will be able to exert considerable upward leverage on international oil prices through manipulation of their output levels. Canada will continue to have an incentive to price its oil at international levels in order to remove the effective subsidy on imported oil. Constant-dollar international oil prices of roughly three times the current domestic price are expected by the U.S. Department of Energy for the year 2000.

Ontario is almost entirely dependent for fossil fuels on sources outside the province. The income loss that comes with higher energy payments can be minimized basically in two ways: by reducing the use of "imported" fuels and by increasing net exports of goods and services. When conservation and inter-fuel substitution are cost-effective they offer an efficient and reliable way to reduce the province's energy deficit. Increasing net exports entails the element of risk that arises in penetrating new markets during a highly competitive period. The recycling of the income transferred to the producing provinces will probably fall well short of offsetting the loss in demand stimulus to the Ontario economy.

Ontario's criteria for cost-effectiveness in the energy sector will depend on the weight that is attached to the security of supply that comes with indigenous options (including conservation). When assessing the province's options for saving energy and substituting electricity or renewable energy forms for fossil fuels, it is suggested that the best approach would be an analysis of the total end-use system. A transition strategy away from fossil fuels should balance the incremental cost of delivering and utilizing electricity from nuclear plants against the unit cost of conservation or renewables, taking into account the load characteristics of the end use. The incremental cost of utilizing electricity becomes an important factor for the transportation sector.

The relative incremental unit costs that result from analysing Ontario's energy options on a uniform basis should serve as guidelines for a provincial energy policy. Implementing these options in the long-run interest of the province will make it necessary for the government to use its wide range of influence over market forces. In some cases, regulation may be desirable. However, early adjustment through market forces could reduce the risk of having to use severe measures such as mandatory controls later on.

Figure 1.1 Ontario's Energy Options

Natural gas — western Canada

Crude oil — western Canada

Electricity — Manitoba

Indigenous options
1. Uranium
2. Hydroelectricity
3. Other renewables
4. Conservation

Electricity — Quebec

Coal — western Canada

Coal — U.S.A.
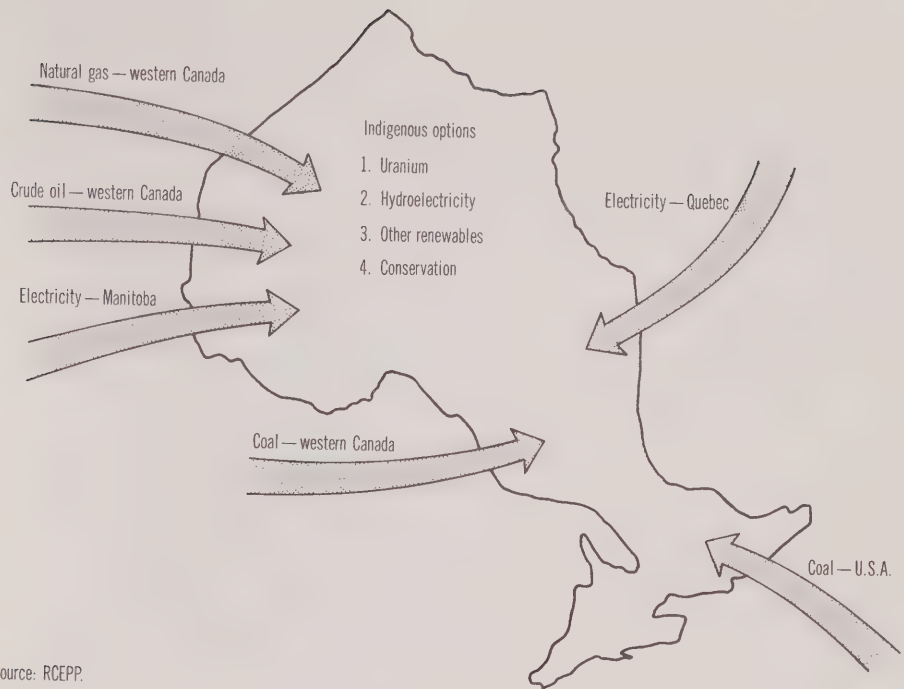
Source: RCEPP.

Figure 1.2 Financial Flows Associated with Ontario's Energy Options

Some recycling of oil payments

Income transfer to the west to pay for fossil fuels

Revenues from exports of non-energy goods and services

Revenues from sales of electricity to U.S.

Debt-service payments in U.S. dollars

U.S. dollars to pay for coal imports

Capital inflow from U.S. (must eventually be repaid)

Source: RCEPP.

CHAPTER TWO
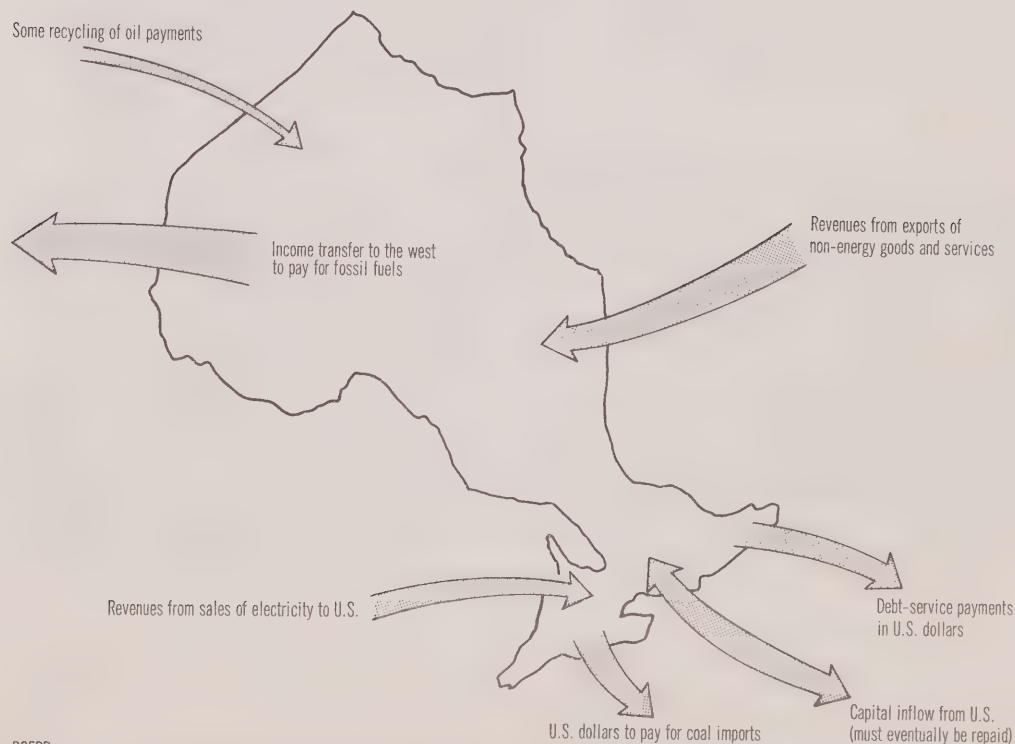
Capital Availability

In 1976, when the Ontario Treasurer imposed borrowing constraints of $1.5 billion a year on Ontario Hydro for the three years, 1976-8, the availability of capital emerged as a major consideration in the planning of Hydro's capacity expansion programme. The action was taken because it was realized that Ontario's prime credit status in international bond markets would be at risk if the provincial government attempted to carry through its borrowing intentions on behalf of Hydro; at that time, Hydro's capacity expansion programme called for $2.1 billion in 1977, rising to $2.6 billion in 1980.

In 1975, the borrowing by the Ontario government for its own use and on behalf of Ontario Hydro reached about $1.86 billion in the public capital markets, a significant increase over the $0.7 billion of 1973 and the $0.5 billion of 1974. The lion's share of the new debt, $1.56 billion, was issued on behalf of Hydro. The remaining $300 million, along with about $1.2 billion in non-public funds (principally pension plans), was needed by the province to finance its fiscal 1975-6 deficit.

The impact of the capital availability problem was not restricted to Ontario Hydro. At the same time that it constrained Hydro's borrowing, the province initiated a policy of fiscal restraint and began serious efforts to balance its budget, setting 1980 as the target year for achieving this. It was apparent that Hydro, by itself, could absorb all the funds that were available to the provincial government in the public market and most of the non-public funds as well. To preserve fiscal flexibility in a period when revenues were difficult to predict accurately, it was prudent for the government not to plan on borrowing continuously up to and beyond a point that threatened its AAA credit rating. An important aspect of the goal of balancing the budget may have been to make room for Ontario Hydro to borrow the non-public funds that would otherwise have been used to finance the deficit. If so, this represented a significant policy choice. The question of how much of the long-term capital available to the province should be allocated to Ontario Hydro for spending on the production of electricity rather than to other government services or capital projects is always, whether or not it is explicitly so described, a government policy decision. In fact, when the utility is a public enterprise, it is at the core of electric power planning.

This chapter introduces the concept of capital availability, summarizes the methodology used to estimate it, and outlines the major determinants of Ontario Hydro's and the Province's requirements for long-term borrowing in the public capital markets. But, first, the development of capital availability and requirements projections since the imposition of borrowing constraints on Ontario Hydro in 1976 will be reviewed.

A Constraint on Ontario Hydro's Spending Plans

Beginning in 1976, capital availability emerged as an overriding constraint on both the size and the composition of Ontario Hydro's capacity expansion programme. However, by 1979, with the stretching-out of the construction programme that accompanied the downward revisions of its load forecast, Hydro's capital and hence its borrowing requirements were dramatically reduced. By themselves, they no longer endanger the credit status of the province. However, in combination with other demands for long-term public capital, the issue of capital constraints on Hydro expansion may return.

Table 2.1 compares Ontario Hydro's 1977 and 1978 projections of capital availability and capital requirements. The net borrowing potential that would have remained for the rest of the Ontario government, i.e., Hydro's surplus or shortfall, is plotted in Figure 2.1. Estimates of capital availability made by the Ministry of Treasury and Economics have been used to calculate the second set of capital surplus (shortfall) projections shown in that figure. Figure 2.2 superimposes the 1978 Hydro capital availability projection (in terms of gross issues) on Hydro's total annual borrowing requirements for the 1979 expansion plan. Figure 2.3 demonstrates the improvement in the capital availability situation in the 1979 programme resulting from the cuts in the 1978 expansion programme.

Table 2.1 Ontario Hydro Capital Surplus (Shortfall) – Borrowing Requirements and Capital Availability in Terms of Net Increase in Debt Outstanding ($ millions)

	1977 Projection			1978 Projection		
	Requirements[a]	Availability	Surplus (Shortfall)	Requirements[b]	Availability	Surplus (Shortfall)
1977	1,226	1,671	444	–	–	–
1978	1,149	1,635	486	1,509[c]	1,516	7
1979	1,666	1,816	150	1,713	1,504	(209)
1980	1,646	1,693	47	1,809	1,405	(404)
1981	2,045	1,908	(137)	1,948	1,472	(476)
1982	2,561	1,829	(732)	1,998	1,694	(304)
1983	2,651	2,085	(566)	1,561	1,933	372
1984	2,848	2,330	(518)	1,554	2,442	888
1985	2,925	2,487	(438)	1,612	2,607	995
1986	3,349	2,763	(586)	1,675	2,501	826
1987	3,892	3,239	(654)	2,030	2,347	317
1988	4,727	3,547	(1,180)	2,460	2,569	109
1989	5,361	3,707	(1,654)	2,647	2,625	(22)
1990	5,856	3,797	(2,059)	2,488	3,034	546
1991	6,244	4,100	(2,144)	2,355	3,105	750
1992	6,745	4,433	(2,312)	2,653	3,258	605
1993	7,287	4,421	(2,866)	3,292	3,549	257
1994	8,138	5,150	(2,988)	3,657	3,901	244
1995	8,626	5,653	(2,975)	3,539	3,955	416
1996	8,906	5,848	(3,058)	4,180	4,314	134
1997				4,640	4,662	22
1998				5,401	4,899	(502)

Notes:
a) 1977 Requirements Associated with LRF48A.
b) 1978 Requirements Associated with LRFP781201.
c) Actual.
Sources:
1977 – "Review of the System Expansion and Financial Plane", April 1977, Ontario Hydro.
1978 – "Long-Range Financial Projection, 1978-1998", Comptroller's Division, 781201, Ontario Hydro.

These tables and figures reveal the impact of reduced capital requirements, moderated by lower projections for capital availability, on the expectations for capital surpluses or shortfalls in the projections made in 1977, 1978, and 1979. In 1977, the capital availability and requirements projections resulted in capital shortfalls that continue after the three-year period of borrowing constraint (already reflected in reduced spending in 1977-9) and that become immense by the mid 1990s. By 1978, lower capital requirements eliminated Ontario Hydro's financing problems after 1982. However, the surplus capital available to the Ontario government that would have been left over for provincial deficit financing after Hydro's revised capital requirements had been met was quite small. During the forecast period, it never exceeded 3 per cent of the provincial budget (which, it is estimated, will grow at the same real rate as the economy as a whole). The surplus would leave little room to finance provincial government counter-cyclical fiscal policies or unexpected revenue shortfalls. For 1979-83, four years of capital shortfall were projected because planned expenditures were not reduced in line with the economic factors that affected both the load forecast and the capital availability projection. However, following the deferral of several nuclear units in the 1979 Ontario Hydro system expansion plan (which reduced the order level for reactors to one per year in 1982-94), capital requirements in the 1980s were cut drastically and, in the process, the pressure on debt financing in the years 1979-82 was relieved (Figure 2.3). It is quite possible that a desire to keep rate increases moderate, during the period when debt financing would have been restricted, contributed to the deferral of capital expenditures in 1979-82.

The financing problem now on the horizon is the quadrupling of Ontario Hydro's annual borrowing requirements between 1986 and 1994 as the expansion programme accelerates after being stretched out in the early and mid 1980s. In itself, this should be manageable. Whether borrowing constraints will be imposed on Ontario Hydro in the future will depend, in part, on the extent to which the Ontario government can finance its deficits without tapping public capital markets and, in part, on the industrial and energy policies the province adopts. For example, a strategy of adding nuclear capacity in a greater proportion than 2:1 compared with coal would be limited by capital availability if system growth exceeded a long-term average annual rate of 5.5 per cent (according to Ontario Hydro's System

Expansion Program Reassessment Study — final report, February 1979). This question is examined at greater length later in this chapter.

Capital Availability Analysis

The Ontario Treasury defines capital availability to be "the maximum sustainable borrowing level consistent with maintenance of the province's prime credit status".[1]

Formally, credit status is measured by the bond ratings assigned by the two major U.S. rating agencies: Standard and Poor's, and Moody's. Since 1977, the Ontario government has had an AAA rating from both agencies, the highest each assigns. In practice, the quality of a credit is reflected in its yield spread. Over the period 1974-7 (which encompasses about one cycle in the fluctuations of yield spreads), the average yield spread between utilities rated AAA and AA was 25 basis points (0.25 percentage points). Similarly, between AAA and BBB utilities the average was 164 basis points (1.64 percentage points).

Favourable yield spreads convert directly into lower payouts over the life of the bond. When Ontario borrows $1.5 billion at its prime rate for 30 years, it saves about $110 million in nominal terms or $40 million in present value, compared with an AA credit when the same bonds are being floated. The savings are more dramatic when contrasted with the financing charges facing a BBB utility, the most common rating for investor-owned utilities in the United States. The total payout is reduced by $740 million over the 30-year term, which has a present value of about $260 million. On the assumption that Ontario Hydro, borrowing without the provincial guarantee, would have a lower rating, it is clear that the provincial guarantee of Ontario Hydro's bonds considerably reduces the cost of Hydro's expansion programme.

High credit status confers a variety of benefits other than cheaper financing. Principal among these is the user's flexibility of choice concerning the timing of issues. This is particularly advantageous during slumps in economic activity, tight financial markets and high inflationary periods when institutions feel there is the most risk (of capital loss) in committing themselves to long-term bonds. AAA credits may be able to go to the market when lesser credits would be best advised to postpone their offering.

In a paper that introduces its capital availability methodology, the Finance Management Branch of the Ontario Treasury states:

> Over the long run, maintenance of credit status assures the greatest continuity of access to the largest pool of funds. It thus reinforces the goal of achieving a level of potential borrowing that is both sustainable and a maximum. Loss of credit status, due to excessive borrowing in the short-run, would reduce long-term borrowing potential and be inconsistent with the essential nature of capital availability analysis.[2]

This implies that, should Ontario's bond rating be reduced to AA, the supply of capital available to the province would probably not increase, over the long term, despite the increase in yield. This would occur, in part, because some institutional portfolios are restricted to AAA credits (particularly true for international issues) but also because the lower rating would affect the value of the bonds already issued in the market, resulting in capital losses for Ontario bond-holders as the interest rate rose. Also, a reclassification would indicate a downward trend in the underlying financial and economic viability of the debt-issuer, which, in the minds of lenders, increases the risk of future capital losses and so reduces their confidence in holding further bonds. Other experts on the capital markets, appearing for example before the Ontario Energy Board, have confirmed the Treasury view, despite the fact that it appears to run counter to the standard economic hypothesis that the supply of capital responds to the rate of return offered by the investment.

On two occasions, the RCEPP heard economists from the major Canadian banks assert that, if energy projects are viable, financing can be found, even as the energy share of total investment grows and the investment share of GNP is pushed to precedent-setting levels. As a general statement, it is true that the Canadian capital markets are considered efficient in directing resources where they may most profitably be employed. With the real increase in energy prices that has occurred in the last few years, the energy sector has definitely become a much more attractive investment opportunity. However, such an aggregate analysis of capital markets lumps together many diverse borrowing situations. Several institutional characteristics distinguish this financing situation from the more common private sector ones. Foremost is the perception by rating agencies and portfolio managers that the government of Ontario, by guaranteeing Ontario Hydro bonds, is the primary borrower in the market-place. While

Hydro's financial soundness is important, it is only one component of the financial integrity of the provincial government. The financial statistics of a Crown corporation may not, then, be crucial to a lender who has confidence in the economic policies of the government guaranteeing the debt. As a corollary, the rate of return to public sector energy projects may not be as central as it is to fund raising for private enterprise. Hydro's debt financing is forthcoming largely because it is assumed that the province will be able to meet its financial obligations. This quality is not enhanced in the long term by increasing the yield on its bonds.

A second characteristic of Ontario Hydro's borrowing programme that differs from many private-sector financing situations is that the utility places a great premium on the continuity of the availability of funds over a long time horizon. Hydro must finance a steady stream of electric power facilities and so must satisfy the criteria applied by portfolio managers and bond-rating agencies to maximize long-term debt funding. Increases in yield would generate only a temporary but not a sustainable increase in Ontario's ability to borrow.

Ontario's Credit Rating

Credit status may be changed by a rating agency if a regular reassessment of the economic and financial health of the issuer of the debt reveals any significant alterations to the circumstances in which the original rating was made. The issuer would be notified well in advance of any intention to change his rating. It was probably this sort of feedback from the financial community in New York that caused the Treasurer to take the steps he did in 1976.

The factors that go into determining a credit rating in the first place are somewhat intangible, bordering on subjective. Rating agencies monitor economic performance closely, as noted above. However, they are primarily interested in the resiliency of the economy issuing the debt. In Ontario's case, the size and diversity of the industrial structure gives this province an advantage over more specialized provinces. In addition, the quality of the civil service and the stability of the political system impart confidence that payments will be made on schedule. From the perspective of the rating agencies, judgement-laden attributes such as sound economic policies and the sound management of government budgets are critical.

Apparently, the Ontario government has satisfied the agencies in the years since concern was raised by the 1975 borrowing programme. Ontario remains the only province with an AAA rating from both rating agencies in spite of the fact that, using many of the common measures of indebtedness, Ontario's position has deteriorated in comparison with those of Alberta, Saskatchewan, and Quebec. The less than strict observance of conventional measures of indebtedness by rating agencies has its counterpart in the insensitivity of provincial ratings to the degree of financial soundness of the associated public utilities. Even through the largest part of the long-term indebtedness of the province may be the guaranteed debt of an electric utility, the financial ratios of the utilities seem to affect the provincial credit status only if they change sufficiently to motivate a reassessment of the contingent liabilities on which the province's financial soundness was initially evaluated. Standard and Poor's "Approach to International Ratings" states:

> A particular country's willingness and economic ability to honour its obligations supercedes the risk considerations connected with lending to individual entities below the sovereign government.... The relative weights that we place on such relationships [with government and the financial community] vary from case to case and from country to country, but in the final analysis may be as important as, or more important than, any particular set of financial ratios.[3]

In contrast to the rating agencies, underwriters appear to pay more attention to the financial soundness of the utility on whose behalf the debenture is being issued. A financial comparison of Hydro-Québec and Ontario Hydro, made by Kidder, Peabody, and Company in 1977, demonstrates that since about 1970 Hydro-Québec has had superior performance in almost all key financial ratios. It concludes that "Hydro-Québec deserves to be ranked with our highest quality utilities on its own merits".[4]

Quebec's AA rating must then be indicative, relatively speaking, of lower investor confidence in the province than in the utility. Conversely, in the case of Ontario Hydro, the strength of the province's guarantee seems to have overcome any concern regarding the deterioration in Ontario Hydro's key ratios in recent years.

Nonetheless, there is some agreement that it would undermine the intangible basis on which ratings are determined were the government itself to cause a deterioration in the utility's financial ratios in

the course of interfering in its operations for the purpose of achieving economic policy objectives. Here, it may be more the method that triggers the alarm than a precise value of the debt ratio and other financial statistics that result (see Table 2.2 for definitions). For this reason, explicit government transfers to Ontario Hydro would be preferable when non-viable projects are undertaken to achieve wider provincial objectives.

Table 2.2 Ontario Hydro's Key Financial Statistics

$$\text{Debt ratio} = \frac{\text{debt}}{\text{debt} + \text{equity}}$$

$$\text{Return on assets} = \frac{\text{income before interest}}{\text{net assets}}$$

$$\text{Interest coverage} = \frac{\text{net income} + \text{gross interest}}{\text{gross interest}}$$

$$\text{Return on equity} = \frac{\text{net income}}{\text{equity}}$$

The component terms are defined as:

debt	= bonds payable
	+ notes payable
	+ plant purchase agreement
	+ head office lease obligation
equity	= accumulated equities
	+ reserve for stabilization of rates and contingencies
	+ contributions from the Province of Ontario
income before interest	= revenues
	− costs in the statement of operations
net assets	= net fixed assets in service
	− contributions from the Province of Ontario
	+ estimated allowance for working capital based on 10% of net fixed assets in service
net income	= debt retirement provision
	+ provision to, or
	− withdrawals from the reserve for stabilization of rates and contingencies (excluding any extraordinary items)
gross interest	= interest and amortization on bonds payable
	+ interest on notes payable, plant purchases agreement and on head office lease

Source: Ontario Hydro, Financial Forecast, 1978-83, Finance Branch, 780417, p. 28.

Estimating Capital Availability

Long-term capital availability forecasts are prepared by the Finance Management Branch of the Ontario Treasury and the Economics Division of Ontario Hydro. The two groups are in substantial agreement concerning the appropriate theoretical framework and are currently producing quite similar aggregate estimates for the capital available to the provincial government annually to the mid 1990s. Some contentious issues remain that may cause forecasts to diverge in future, but the differences are not likely to be of such magnitude as to result in major policy confrontations. Table 2.3 compares the Ontario Hydro and Ontario Treasury projections of capital availability that were made in 1978.

Table 2.3 Comparison of Ontario Hydro and Ontario Ministry of Treasury and Economics Projections of Capital Availability for 1978

	Ontario Hydro minus Ontario Treasury[a]
1978	199
1979	110
1980	(88)
1981	(184)
1982	(100)
1983	118
1984	210
1985	389
1986	175
1987	(39)
1988	94
1989	153
1990	208
1991	92
1992	168
1993	156

Note a) Negative results in brackets.
Source: Ontario Hydro, "Capital Availability, 1978-2000", December 1978, p. 30.

The trend since 1975 has been for Ontario Hydro to adopt Treasury methodology for its long-term projections while relying on its own Treasury Division for short-term projections of gross new bond issues. Co-ordination between the government and Hydro has improved as a result.

The Treasury analyses capital availability, using a stock adjustment model that attempts to quantify the amount of a particular borrower's debt that lenders in a bond market are prepared to hold. The stock-adjustment approach to debt outstanding in the capital market assumes that "Decisions to purchase new issues reflect a lender's desire to adjust his holdings of a stock of debt".[5] The forecasting procedure is carried out in two stages which, in practice, may be difficult to separate. The first stage is to project the growth of the relevant capital markets as a function of the factors determining the flow of funds into each market. Conditional on the level of detailed data available, the desired stock of bonds will most likely be modelled as a function of national income, and may also depend on yield, the inflation rate, savings rates, yields of other financial instruments, etc.

The second stage is to develop an estimate of market share to apply to the projections of debt outstanding in the new issues of each market. It is at this point that credit status enters the picture. Individual lenders are expected to allocate their portfolios among fairly set combinations of yield and risk. As a result, market share only grows with an increase in the yield of the issue. A permanent increase in market share may threaten credit status. Ontario's market share is projected assuming a continuation of the trends of the recent past, that is, on the basis that there is no loss of the current status.

The Canadian Bond Market

The Canadian market is the preferred source of funds for Ontario because of the province's established integrity and because, without the foreign exchange risk, there is increased accuracy in estimating total borrowing costs. International credit ratings, though not directly relevant in the domestic market, do influence lenders and are reflected in yield spreads. Yields payable on Ontario issues are lower than those on issues of other provinces and electric utilities and are comparable to those paid by the Government of Canada.

Market Growth. The Treasury model uses nominal GNP as a measure of wealth in its historical analysis of the Canadian bond market. The results show an elasticity of debt outstanding to GNP of 0.7 (i.e., a 10 per cent increase in nominal GNP results in a 7 per cent increase in debt outstanding). The expected return on bonds, the yields of competing assets, and Canada-U.S. exchange-adjusted yield spreads are other significant explanatory variables in the model. Ontario Hydro's analysis of capital market growth is also dominated by forecasted national income, though the explanatory variables in the rest of the model are not identical.

Essentially, it is the nominal GNP forecast, consisting of real output growth and inflation rate components, that drives both models. In many areas of economic analysis only real growth matters, but in the financial markets the inflation rate is quite important. If the inflation rate varies over time, it will

influence interest rates, which will lead to substitution between financial instruments and so affect the growth of capital markets. The dependence of capital availability projections on short- and long-term forecasts of nominal GNP, which are frequently revised, explains why capital availability estimates can change so much from one year to the next. However, because real output growth is also a key determinant of the load forecast, a reduction in the projected GNP growth rate will lead to reduced growth in the demand forecast for electricity at the same time that it reduces the forecast ability to finance new plants.

Econometric models of the growth of the Canadian bond market may not be able to capture the effects of major structural changes in the composition of the long-term capital market. One of the areas of current debate between Ontario Hydro and the Ontario Treasury is the role the block of funds used for mortgages in the 1970s will play in the 1980s as housing construction slows. Hydro expects a larger increment to the long-term debt market than the Treasury, though the difference between their estimates is not large considering the uncertainty surrounding the GNP forecast.

A few comments on this issue are in order here. Traditionally, mortgages were a long-term financial instrument, but since the high inflationary period began in the early 1970s, they have been designed more cautiously — on a five-year, renewable, variable-interest basis. Should the inflation rate stabilize, the lenders in the mortgage market may be prepared to direct their surplus funds to other long-term uses opening up in the energy sector and to the provincial debt markets. On the other hand, should the present uncertainty continue, it may be argued that these funds may become short-term financial loan instruments of the banks and so more suitable for consumer or business loans. A federal Ministry of Energy study entitled "Financing Energy Self-Reliance" predicted shifts out of the mortgage market to generate the major new source of domestic financing for the debt issues of electric utilities. It predicted that the share of GNP going to residential construction would fall from 5 per cent in 1975 to less than 3 per cent in 1990.

> Banks, trust companies, pension funds, and life insurance companies will gradually shift from mortgages to bonds for the same reason that 7 years ago they shifted to mortgages because the prospective rate of return, driven by demand, is higher.[6]

EMR recognizes that such a shift will require a new approach to risk diversification by these financial institutions.

Market Share. The Treasury predicts that Ontario's share of the Canadian bond market will remain constant at 10 per cent. Hydro sees potential for growth to 12 per cent in the 1990s.

International Debt Issues

Prior to 1975, Ontario explored the U.S., Eurodollar, German, and Swiss markets with the primary intention of being able to take advantage of low interest rates — speculating that future exchange-rate shifts would not eliminate the expected savings in borrowing costs. With the record capital demand in 1975, Ontario tapped all sources in which it had had previous exposure. Foreign borrowing netted $1.1 billion out of the total debt incurred of $1.9 billion. Since 1976, even with borrowing constraints, the Canadian bond market has supplied only about half of the funds sought by Ontario Hydro. The remainder was borrowed in U.S. dollars, either in New York or in Europe.

The preference for the U.S. market in recent years is clearly a result of the capital losses experienced as the Canadian dollar depreciated against the German mark and the Swiss franc. The 1974 OPEC oil price increase, accompanying economic dislocation in industrialized countries and differential national inflation rates, triggered a series of exchange rate adjustments that would have been difficult to predict given world experience with flexible exchange rates. Fortunately, only 2.5 per cent of Hydro debt outstanding is denominated in those currencies.

The risk of foreign exchange losses has resulted in an Ontario Hydro policy to incur debt in currencies other than the U.S. dollar as a last resort only, or "when economic analysis of such markets in terms of interest rate differentials and foreign exchange forecasts suggests decided advantages".[7] Hydro has analysed the Japanese, European currency, and petro-dollar markets but is placing minimum emphasis on overseas sources in preparing its total capital availability projection. Should the Canadian dollar show signs of long-term strength relative to these currencies, or, more fundamentally, should the outlook for inflation fall credibly to levels prevalent in Germany, Switzerland, and Japan, then there may be a resurgence in non-U.S.-dollar issues. In the meantime, the focus will continue to be on the U.S. and Eurodollar markets.

U.S. Dollar Markets. Between fiscal year 1974-5 and 1977-8, 47 per cent of the province's funded liabilities were denominated in U.S. dollars. During the first half of this period the Canadian dollar appreciated in value. However, since its 1976 high of $1.03 U.S., the Canadian dollar has depreciated by 20 per cent to its present trading rate of around $0.85 U.S., which is roughly half of the devaluation suffered relative to European currencies and the yen.

Out of necessity, Ontario has continued to borrow in the U.S. in order to be able to finance its committed programmes without exceeding the capital availability estimates for the Canadian bond market. The preference for the U.S. market over other international markets is founded on the strong trade and financial links between Canada and the U.S. Because economic ties are close, the U.S. dollar/Canadian dollar exchange rate is expected to be more stable than Canada's exchange rate with any other trading partner. This does not, however, imply long-term parity between the two dollars.

The eventual resting place of the Canadian dollar will depend on many factors, including the quantity of foreign savings attracted to Canada (particularly for energy sector projects) and the extent to which Canadians attempt to compensate themselves for cost-of-living increases associated with the depreciated dollar. The consensus of opinion is that the dollar will appreciate somewhat over the next several years. It would not be surprising, however, if it remained in the $0.90 or lower range for some time. Although U.S. dollar borrowing does not seem to involve undue risk of foreign exchange losses, it is unlikely that the total borrowing costs of U.S. issues will be quite the bargain they once appeared to be.

Despite the depreciation, foreign exchange losses on Ontario bonds are not likely to be severe. The Treasury claims that at a $0.90 U.S. exchange rate, U.S. denominated debt outstanding still has a marginally lower yield to maturity than Canadian debt. Of course, at the time of borrowing, costs were estimated to be about 10 per cent lower. Still, any debt since 1975 that was raised in U.S. dollars could only have been incurred in Canada by threatening Ontario's credit status and crowding private-sector borrowers out of the market.

The major risk in basing about half of the financing of a capacity expansion programme on U.S. funds is the possibility that the U.S. government might impose restrictions on capital outflows or, in the extreme, close American capital markets to foreigners. In the past, Canadian borrowers have been preferentially treated in the U.S., having been exempted from the interest equilization tax that kept other countries away from U.S. markets until 1974 (when it was repealed). Favourable treatment in the future could be used as a bargaining chip in the continental energy game, but it is unlikely that the U.S. would choose to solve its currency problems through restrictions on capital markets. With the quantity of U.S. dollars in Eurodollar markets and held as a reserve currency, the U.S. must rely on confidence in its economic policies to stop a run on its currency. Nonetheless, should the international monetary system, based on flexible exchange rates, become unstable, capital restrictions are a possibility in the years ahead.

Perhaps a more serious concern for Ontario is whether capital expenditures on energy projects in the U.S. over the next decade will crowd foreign borrowers out of American markets. A study done in 1978 by Bankers Trust Company (entitled "U.S. Energy and Capital — A Forecast, 1978-82") does not find any evidence that energy-sector expenditures will strain the U.S. capital market in the period covered. In the longer term, capital requirements for U.S. energy projects could be staggering if Americans mobilize themselves to reduce their dependence on imported energy. In the same vein, a large U.S. federal government deficit could put temporary pressure on the market.

The major cost of borrowing in the U.S., rather than in Canada, is the impact of a large surplus on the capital account on the Canadian dollar. At a time when most Canadians are concerned about the low level of the dollar, it may appear ridiculous to mention the relative appreciation of the dollar that occurs as a result of Ontario's borrowing abroad. Nonetheless, just as Ontario is expected to benefit, relative to other provinces, from a depreciation (because of the importance of exports to the Ontario economy), so Ontario's competitiveness in foreign markets suffers when the currency is overvalued.

As recently as 1976 it would have been relevant to debate whether many of the benefits of Ontario Hydro's high Canadian content on purchases for its construction programme (about 85 per cent Canadian and 70 per cent Ontarian) were not dissipated when about 50 per cent of the capital came from offshore. In 1978, for instance, Hydro's capital expenditure programme brought about an estimated net inflow into Canada of $560 million, an amount that has been estimated by the University of Toronto's "TRACE" model of the Canadian economy to cause an appreciation of nearly $0.01 in the

Canadian dollar. By encouraging imports and discouraging exports, Canada and Ontario would experience an increased trade deficit that would partially offset the capital inflows. Hydro, as a whole, balanced its U.S. inflows and outflows in 1978 because of its purchases of U.S. coal worth $350 million and interest payments on U.S. debt of roughly another $350 million. However, as these payments in U.S. dollars are not sensitive to changes in Hydro's capital expenditures, they do not offset the negative impact of foreign financing on the net benefits to the province of Hydro's construction programme.

U.S. Market Growth and Ontario's Market Share. Both the Treasury and Ontario Hydro models for U.S. market growth are simpler than their Canadian market counterparts running entirely off nominal GNP growth. Though bonds outstanding are about 47 per cent of U.S. GNP, foreign borrowers account for less than 4 per cent of the U.S. bond market. Canadian debt outstanding is now about two-thirds of total foreign debt in that market. It is expected that Canada will continue to increase its share of the U.S. market and, at the same time, that Ontario's share of outstanding Canadian issues in the U.S. will increase from about 14 per cent in 1979 to 19 per cent in 1993.

Factors that Could Lead to Constraints on Ontario Hydro Borrowing in the Future

Figure 2.2 illustrates that the 1979 capacity expansion plan, designed to meet a 4.5-5.0 per cent load-growth forecast, is financeable. Expansion plans associated with lower peak load forecasts would also avoid capital shortfalls, though the gap between capital requirements and availability need not actually widen by that much.[8]

Compared with the economic outlook that determined the 1978 capital availability projection, there appears to be considerable room for additional borrowing in the 1980s, although an updated capital availability projection would probably reduce the capital surpluses shown in Figure 2.2. For the purpose of the section that follows, it will be assumed either that developments in energy policy and industrial strategy motivate an accelerated expansion plan or that economic prospects worsen so that the gap between capital availability and Ontario Hydro's requirements narrows. Simply allowing for a contingency fund to finance a 3 per cent error in the revenue forecast for the provincial budget would involve setting aside about $0.5 billion now, rising to about $1.0 billion by the early 1990s. In this context, the next few paragraphs suggest less obvious factors that may increase Hydro's borrowing requirements. The next section addresses the issue of the continued allocation to Hydro of the entire public debt-financing available to the province in the 1980s.

Ontario Hydro's Debt Requirements

Ontario Hydro's capital requirements forecast makes assumptions about real cost escalation, the target nuclear:coal generation mix, and the corporation's debt ratio. Unexpected increases in any of these parameters would boost the debt-financing needed to complete a given construction programme.

Real cost escalation could occur if the manpower and material resources that Ontario Hydro demands become relatively scarce or their prices are increasingly set outside the market-place. The cost of CANDU nuclear components could go up significantly if the industry is reduced to a single supplier of each component. This could happen unless sales outside Ontario boost the annual reactor order level beyond present expectations. Costs may also rise if original designs prove to be inadequate or unexpected expenses emerge.

Ontario Hydro's debt ratio will fall by itself from its current high level of 0.86 as the expansion programme slows down in the 1980s and could drop below the target ratio of 0.80 to 0.82 depending on the policy adopted with respect to the interest coverage ratio (see Table 2.2). This will happen because, the less plant there is under construction and incurring debt relative to the plant that is in service and generating revenue, the lower will be the ratio of debt increase to equity contributions. After 1986, however, under the 1979 expansion plan, the debt ratio could start to rise again. Aside from these natural fluctuations, the debt ratio is an important provincial policy lever because it determines the electricity rate increases Hydro needs in order to complete the financing of its expansion plan. Nonetheless, a high debt ratio cannot achieve both low electricity prices and high construction levels without eventually running into capital availability constraints. The Ontario Energy Board review of Ontario Hydro's 1980 rate case concluded that "the question of how much Ontario Hydro borrows relative to how much it collects from customers today is an important fiscal policy issue for the Government of Ontario. It is a matter on which the Government should give policy direction".[9]

The capital crunch in 1976 was largely a result of several years of insufficient electricity rate increases that obliged Ontario Hydro to increase its debt ratio to the point where borrowing constraints were imposed. This pattern could be repeated. On the other hand, the debt ratio may be intentionally reduced to encourage conservation (as rates would rise correspondingly) and to liberate debt capital. Financing problems, almost by definition, arise when the trade-off between paying today and paying tomorrow errs in favour of procrastination.

All in all, unplanned increases in capital requirements will probably not be as significant a factor leading to constraints on Ontario Hydro's borrowing in future as the assumption that the utility will have access to all the capital available to the province.

The Allocation of Ontario's Available Capital to Ontario Hydro

The provincial government's need to issue public debentures depends on the ability of its non-public sources, essentially government-administered pension plans, to finance its deficit. During the 1970s, Ontario borrowed from three pension funds: the Canada Pension Plan (CPP), the Ontario Municipal Employees Retirement Savings plan (OMERS), and the Ontario Teachers Superannuation Fund (OTSF). In 1975-6, $1.26 billion in non-public bonds were issued by these three funds, equivalent to two-thirds of the total provincial debt-financing (excluding Ontario Hydro) in that fiscal year.

Pension funds grow when pension plan contributions exceed the benefits paid out. The outlook for the province's pension funds in the 1980s is still somewhat uncertain, but the issue is really only how rapidly the annual net contributions will fall to zero and then start going negative as the population ages. This process may be slowed down by raising required contributions -- in a sense, a subtle form of taxation.

Since 1978, OMERS has been reorienting itself to invest its funds where it can receive a higher return than the long-term bond market rate that the provincial government has been paying. It will invest some of its contributions in Ontario Hydro bonds for several years but none will be used for provincial financing. The net addition from the Teachers' plan, which is guaranteed by the provincial government, will likely dwindle with the slow growth in the number of new teaching positions. The CPP is under review by the Finance Ministry in Ottawa. A possibly dated forecast by Data Resources of Canada, Inc. (September 1978) showed that the inflow of funds peaked in 1977. As benefits increase relative to contributions, the annual increment to the CPP may decline to zero by the late 1980s and become negative after that.

James E. Pesando of the University of Toronto's Institute for Policy Analysis concluded in 1976: "The dramatic reduction in the future availability of non-public sources of funds is clearly the most important development affecting the outlook for the finances of the Province of Ontario in the next decade."[10]

The Ontario government's intention to balance its budget must be motivated partially by the knowledge that the supply of non-public funds will be contracting severely in the 1980s. Without relying on tax revenues to grow faster than the economy as a whole and without borrowing publicly, the only alternative is to restrain government expenditures. The task will not be easy, as evidenced by the four-year postponement of the target year for balancing the budget since the goal was first announced. It will be especially difficult in a period of slow economic growth. Despite the maturing of the baby-boom age group, the *Fifteenth Annual Review* (1978) of the Economic Council of Canada concluded that spending for social services would probably hold steady in the 1980s unless standards were cut. Any reduced needs for spending on education would probably be balanced by increased spending on health care, including programmes for senior citizens. This would have a strong effect at the provincial level. In Ontario, health and education spending account for about 60 per cent of total government expenditures.

The Ontario government may also wish to increase its financial support of other energy-sector investments in the province (e.g., conservation and public transit) and elsewhere in Canada (e.g., natural gas pipelines from the frontier and synthetic crude oil plants). The amounts involved will not likely be large relative to Ontario Hydro's capital expenditures, but there could be some encroachment on Hydro's borrowing capability.

The Finance Management Branch of the Ministry of Treasury and Economics summed up its perceptions of capital availability analysis as follows:

> The principal implications of this approach to capital availability for long-term planning are that borrowing capacity is finite and that, as a result, the Province and Hydro must coordinate their

activities within the bounds imposed by the limitations to borrowing. By planning together and assessing the relative priorities of Provincial spending and Hydro generation programmes, the Province can assure a financially viable long-term plan embracing both Hydro's capital spending and borrowing and the evolution of the Province's budgetary strategy.[11]

Conclusion

The concept of capital availability has served a useful purpose in restraining provincial government and Ontario Hydro expenditures in a transition period from a high-growth economy with an even faster-growing government sector to a slower-growing economy with a roughly constant government share of provincial income. By adopting a prudent long-term borrowing strategy, Ontario has gone a long way towards ensuring that debt service payment will not impose too heavy a burden on future taxpayers. With Hydro's stretched-out expansion plan, capital availability is not likely to be a constraint on its planning in the 1980s. As this chapter has attempted to indicate, however, the circumstances of the next decade may necessitate close financial co-ordination between the provincial government and Ontario Hydro.

Some observers argue that the capital available to Ontario Hydro is unlimited as long as the investments made are seen to be viable, that is, as long as a market for the power (either domestic or export) exists at future prices. This perspective views Hydro as the issuer of the debt, able to enlarge its share of the capital market by increasing the yield on its bonds. However, should Hydro attempt to go its own way in capital markets, it would effectively become a publicly regulated, private utility and would probably experience the same financing difficulties as U.S. utilities in the same position.

These difficulties would begin with a severe loss in credit status which would probably reduce Ontario Hydro's borrowing power by more than could be offset by increases in yield. Within the financial community there appears to be little doubt that, over the long term, the debt-financing available to Hydro will be maximized if Hydro bonds continue to be guaranteed by the provincial government and it retains its AAA rating.

In adhering to capital availability projections since 1976, Ontario Hydro has had two basic alternatives: slower expansion and less capital-intensive expansion. In opting for a capital-intensive path, Hydro has been obliged to become an advocate of conservation and load management.

Capital availability limits could force the rationalization of the nuclear industry in Ontario unless significant orders for CANDU reactors are forthcoming from outside the province. In the next few years, which are critical for the industry, there will be little financial flexibility that would permit reverting even to the 1978 expansion plan, let alone to more stimulating programmes. By the mid 1980s, if the assumptions embodied in the estimates in Figure 2.2 prove correct, sufficient capital would be available to allow the nuclear construction programme to be advanced to free up coal-fired plants for possible export markets.

Despite the apparent capital availability surpluses in the 1980s, Ontario Hydro's expansion plans could still be vulnerable to financing problems. The major risk is that, in a period of slower economic growth and declining non-public sources of funds, the Ontario government will issue public debentures to finance its own deficit or other energy-related capital expenditures, thereby cutting into Ontario Hydro's borrowing. Also, Hydro's real costs could escalate faster than the rate of growth of the capital markets as activity in the energy sector increases and concern over nuclear power leads to greater expenditures on safety systems. Finally, there remains an element of risk in borrowing in the U.S. as that country mobilizes to resolve its own energy problems.
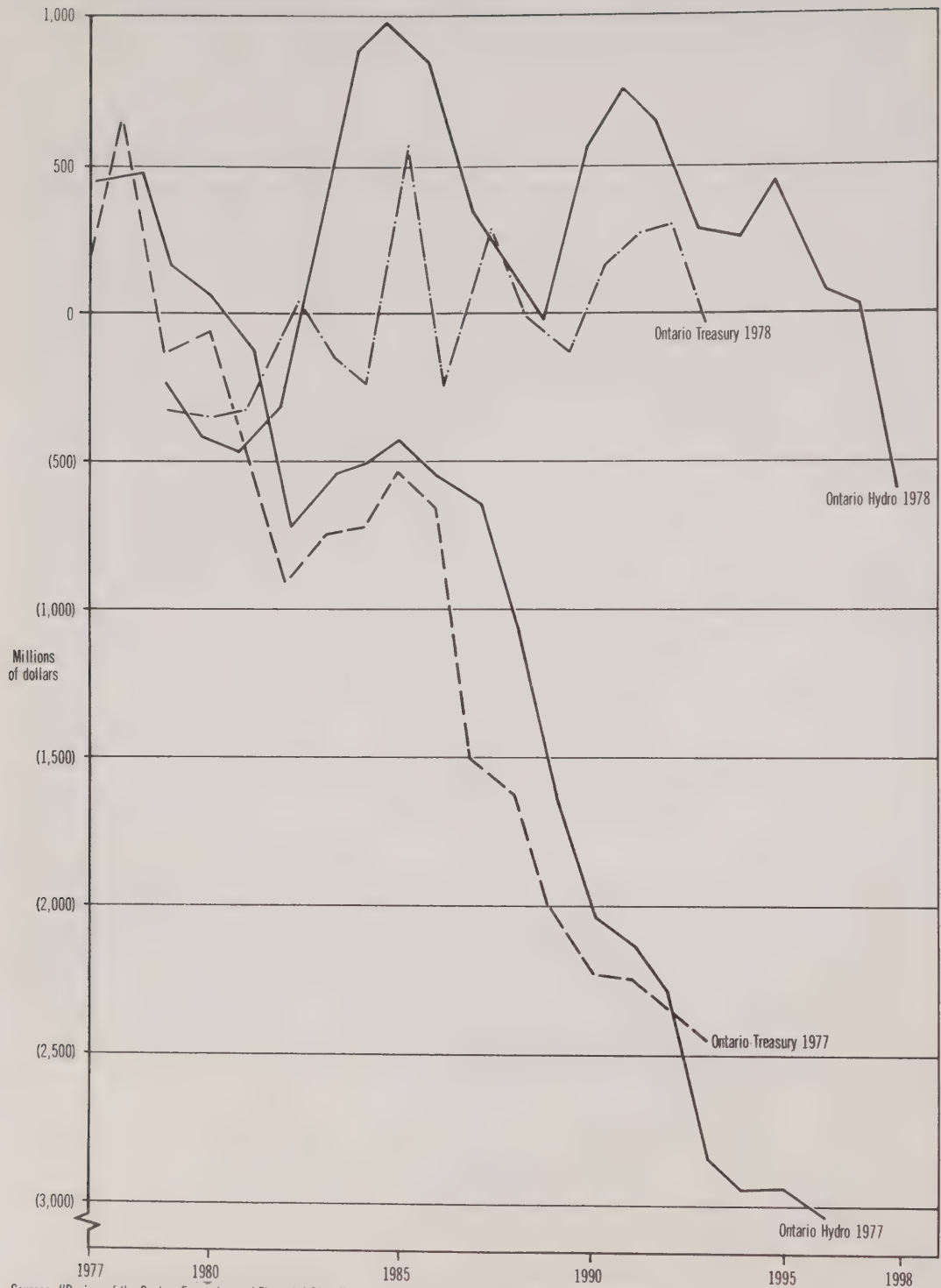
Sources: "Review of the System Expansion and Financial Plans".
Ontario Hydro, April 1977; "Long-Range Financial
Projection, 1978-1998", Comptroller's Division,
Ontario Hydro, 781201;

"Capital Availability to the Province of Ontario
and Ontario Hydro, 1977-1995", Economics Division,
Ontario Hydro, March 1977; "Capital Availability
Analysis: an Introduction", Ministry of Treasury and Economics, August 1978.

Figure 2.2 Ontario Hydro Projections of Increase in Debt Outstanding versus Capital Availability (1979)
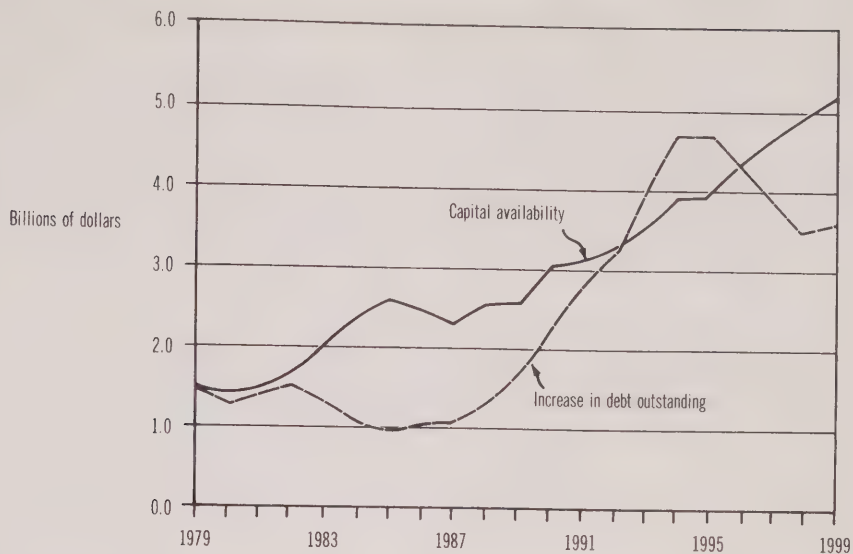
Source: "Long-Range Financial Projection, 1979-1999",
    Comptroller's Division, Ontario Hydro, 790501, p.29.

Figure 2.3 Comparison of Ontario Hydro's 1978 and 1979 Capital Availability Surplus/Shortfall Projections
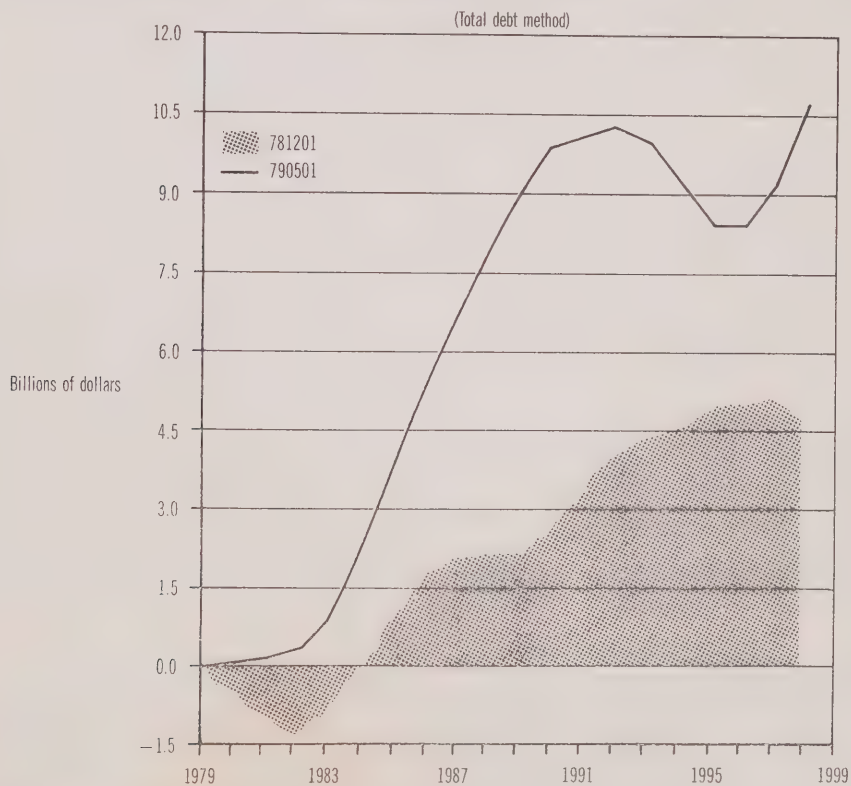
Source: "Long-Range Financial Projection, 1979-1999".
    Comptroller's Division, Ontario Hydro, 790501, p.34.

Selected Costing and Pricing Issues

The rates Ontario Hydro charges for its power and the price of electricity compared with that of other fuels affect the system expansion programme at both the beginning and the end of the planning cycle. In the last few years energy prices have been recognized as a key input to the first stage of the planning process, the load forecast. They play a part second only to the projection of long-run potential growth for the Ontario economy, and, because their prospects and their impact on electricity demand is much less certain, they constitute perhaps the more controversial of the two factors. Much later on, separated in time by about 10 years, energy pricing policies directly influence the demand for installed electricity generating capacity.

Naturally, it would be desirable for the predicted and actual demand for electricity to coincide as much as possible. In the unstable economic environment surrounding the adjustment of industrial countries to higher real energy prices, and with longer lead times for the installation of generating capacity, the chance of load forecast errors is high. Even the degree of uncertainty surrounding the load forecast may not be quantifiable. Pricing policy has the virtue that it may be implemented with a much shorter lead time than new generating stations, and so can help to steer demand in the direction of the committed expansion programme.

The role of electricity tariffs in the planning process is described by Turvey and Anderson in their book *Electricity Economics*:

> Once the target standard of security has been chosen, electricity planners attempt to meet the predicted growth of consumption. Except for the extension of electricity supply to new areas (discussed separately below), planners do not decide directly what this consumption shall be. But though the utility does not fix consumption, it does influence it. The utility fixes tariffs to which the consumers adjust when determining their consumption. The level and pattern of consumption responds, albeit slowly, to the level and structure of electricity tariffs (as well as, of course, to many other things). Thus, the practical problem facing the utility is not: What should the growth and pattern of consumption be? Instead, the practical problem is: What should the level and structure of tariffs be? In considering this question, the utility aims to fix tariffs so that consumers' decisions about consumption result in an efficient use of the country's resources.[1]

The use of pricing policy as a means of demand management will become important for Ontario in the 1990s when accuracy in the load forecast will be at a premium. In the intervening years, forecast precision will not be quite as critical, because, as nuclear capacity displaces fossil-fuelled units for base-load generation, temporary excess capacity may offer savings over stations that are, relatively speaking, technically obsolete. However, any redeeming features of excess capacity could rapidly be eliminated once nuclear stations have penetrated the generation mix to the point where they are on the margin of the base load (i.e., where base load is met only by hydraulic and nuclear plants). This will most probably occur, for the first time, with one of the four Darlington units in the late 1980s. After this point, an over-forecast of demand could lead to an under-utilization of nuclear capacity, and result in a cost penalty because of nuclear's high capital charges.

The likelihood of excess nuclear capacity occurring in the 1990s may be minimized by judicious applications of pricing policy. While reducing the lead time for the approval and construction of new generating stations is the obvious solution to the vagaries of long-term forecasts, it may be easier to achieve a similar effect by using price signals to motivate small-scale, short-lead-time additions to decentralized capacity (e.g., co-generation) or to induce reductions in peak load. The ultimate safety valves for system planning continue, of course, to be imports and exports of power. The potential for exports is discussed in the next chapter. (Interconnections and the potential for imports of power are analysed in Volume 2.)

Mid-course corrections (i.e., deferrals and cancellations) in an expansion programme composed mostly of nuclear stations, and shortages of power, would both be costly to the provincial economy. To reduce the risks of long-lead-time electric system planning in a period of great uncertainty, the Ministry of Energy might at some point consider a more goal-oriented approach to provincial energy strategy. A comprehensive energy strategy could in future years specify desirable targets for electricity, renewable energy conservation, and "imported" fossil fuels. The implementation of such a programme need not take the form of direct government involvement in the energy sector but could, to a large extent, be

motivated by market forces. Where there is effectively no market-place that could competitively set "fair" prices for energy, fuel prices determined within the public sector create the market forces that act on energy consumption and energy supply decisions. The selection of prices for different fuels that are competing to serve a particular end use induces inter-fuel substitution. The general level of energy prices motivates conservation. Implicit in Ontario's energy pricing policies are fundamental judgements about the role of each fuel in the province's energy future.

Though the provincial government is limited in the amount of direct control it can exercise over energy prices, it is not without considerable influence over the bodies that set the prices. It can affect the consumption of electricity and the allocation of resources to the electric sector through policy decisions transmitted to the Ontario Hydro board regarding rate increases, rate structures, and financial targets. It exerts pressure on the federal government in the matter of oil and gas pricing in Canada. It can also introduce taxes or subsidies of its own to alter consumption patterns in a variety of end-use energy markets.

If, at some point in the future, the projection of electricity demand that is used in planning system expansion were largely determined in the context of a provincial energy strategy, some conceivable goals for the utilization of electricity might require that rates diverge from accounting costs. In order to encourage demand, rates might be lower at a time when costs are rising, leading Ontario Hydro to incur financial losses. On the other hand, promoting conservation of electricity, either by charging on the basis of incremental rather than historical costs or by demanding a higher rate of return on Hydro's investments, could lead to significant profits. In the process, long-standing practices that govern the financial relationship between Hydro and the provincial government would have to be reconsidered. The revenue requirement derived from a "power at cost" pricing philosophy already produces a net income that contributes to the financing of Hydro's capital expenditure programme, but large and chronic surpluses or deficits would violate a long tradition.

The costing and pricing of electricity has been under investigation before the Ontario Energy Board for over two years. The Board has examined the matter of implementing changes to Ontario Hydro's power-costing and rate-making principles that could increase in a fair manner the efficiency with which resources are allocated to and used in producing electric energy in Ontario. This immense subject cannot be adequately addressed here. However, a few pertinent aspects of the general topic have been selected for discussion. Because the load forecast is the stage in Hydro's current planning process at which price effects contribute to determining the need for generating capacity, this chapter will provide, first, an overview of the development of the role played by energy prices in the load-forecasting process. Then, since shifts in Hydro's cost structure were to a large extent responsible for the re-examination of the costing and pricing of electricity, the trends in Hydro's cost structure since the early 1950s and the probable future trends will be examined. The long-term pattern is interrupted by a period of transition and excess capacity during the 1980s. The question of short-term versus long-term pricing will be discussed in this context.

The last section of the chapter outlines one of the controversial issues associated with the marginal cost pricing (MCP) of electricity in Ontario. Marginal cost pricing is a generic term for the theoretical goal of pricing in such a way that the purchaser of an additional unit of electricity at any point in time pays the additional costs to society of supplying that unit.

Pricing to reflect social costs involves two stages. One is to find a method of charging for electricity that approximates the incremental cost of supply at any point in time. The other is to determine the rate of return on incremental capital expenditures so that the charge for capital efficiently allocates society's resources to the supply of electricity. In its submission to the OEB, Ontario Hydro sought to develop a structure for electricity rates that was based on MCP principles but would produce revenues no greater than those that would result from rates based on historical or accounting costs. The ability of the revenue requirement to reflect policy choices is the subject of the last section.

The Use of Price Levels in the Load Forecast

Ontario Hydro's submission to the RCEPP describing its load-forecasting methods in 1976, and the testimony presented to the February 1979 session of the Select Committee on Hydro Affairs indicate that Hydro's load-forecasting practices entail the use of judgement by the load-forecasting unit to reconcile the aggregation of individual regions' forecasts with separate econometric forecasts of electricity demand in Ontario. Evidence received during the RCEPP's 1979 hearings in southwestern and

eastern Ontario suggested that the regional forecasts may be more suitable for a one-to-three-year outlook than for the 10-year forecast for which they are nominally designed. This places increased reliance for longer-term planning on the modelling of the statistical relationship between the demand for electric energy and economic variables.

The aggregate demand for electric energy is modelled much like the demand for any intermediate good: as a function of economic activity and relative prices. The relevant price variables are the real price of electricity, that is, the price of electricity relative to the price level for the economy as a whole, and the ratio of the market price of electricity to the market price of the fuels with which it competes. The demand for electricity generating capacity – the input required for system planning purposes – will, in addition, be sensitive to the pricing structure and will depend on whether changing end-use patterns in electricity consumption alter the load factor of the system in the long run.

In a stable economic climate, a statistical modelling procedure could give an air of scientific accuracy to the load forecast. In this unsettled period, a model is probably best seen as a device that presents a quantification of the judgement of the load-forecaster. The rapid increase in world prices for fossil fuels in 1974, and the economic adjustments in the industrialized world that this initiated, have rendered suspect the practice of forecasting from equations fitted to data from the years prior to 1974. Coefficients in an equation estimated in a period of real decline in energy prices and a fairly steady relationship between fossil fuels and electricity prices – the situation that prevailed from the 1950s to the early 1970s – cannot be expected to represent the structure of electricity demand during the transition period to an economy running on substantially higher-priced energy. To illustrate the pat-

tern in relative fuel prices (expressed in 1978 dollars) since 1960, Figure 3.1 plots average oil, gas, and electricity residential heating fuel prices (adjusted for conversion efficiency). Incorporating later electricity demand information into the modelling exercise in order to make it more relevant involves splicing the pre- and post-1973 data. This is a statistical manipulation that leaves the forecaster considerable room to input his judgement concerning the relative importance of recent and past trends.

The following review of the Ontario Hydro load-forecast memoranda for 1976-9 reveals the increasing utilization of single-equation econometric models in the preparation of the forecast of system peak demand. The role of price in these equations has evolved each year. By 1979, the estimate of the sensitivity of electricity demand to prices (measured by the price elasticity[2]) was high enough that a change in rate levels as a result of financial policies or a shift in Hydro's cost structure would have a noticeable impact on the load forecast.

The Load Forecasts for 1976-9

The 1976 Load Forecast Memorandum stated that 'the effects of price increases in all forms of energy are offsetting, subject to their combined depressing effect on the demand for energy generally'.[3] The equation for the expected value of the peak demand, used as a check of the "reasonableness of the forecast",[4] contained only two independent variables: GNP and time.

The 1977 explanatory equation for the East System contained estimates of the elasticities of the electricity demand and energy charges summing to −0.21, as well as output (real GNP) and appliance price elasticities. The first clear specification of electricity price variables implied that demand was fairly insensitive to price. Also, any effect was expected to occur within the first year of a price increase.

Two models were presented with the 1978 forecast. The second, by excluding a time variable, captured more of the structure of the demand process. It broke out real GNP into employment in Ontario and output per employee – the configuration used to describe real potential growth for an economy. Though this equation had a slightly different specification from the previous years, the estimate of the short-term price elasticity was hardly affected, −0.23. The document stated: "It should be stressed that econometric models are not used to produce the forecast but they are of value in validating it, and particularly as a guide to the use of judgement".[5]

The 1979 forecast was presented totally in terms of scenarios for the variables included in the forecast equation or specific qualitative adjustments to the equation where historical structures were not appropriate. With only minor changes in the explanatory variables relative to the 1978 equation, the short-run elasticity of electricity prices was estimated to be −0.53 and the long-run elasticity was given as −0.63. The 1979 equation implies that, with all else constant, a 10 per cent real increase in rates would result in a 6.3 per cent reduction in demand spread out over several years – clearly a significant effect. The dramatic change in coefficients with the addition of one more year of data and the deletion of five

years at the beginning of the data series indicates that the estimated parameters have not yet stablilized.

The forecast chosen for electricity prices was developed for the 1978 expansion plan called "Alternative Z" in Ontario Hydro's "long range financial projection, 1978-98" (dated December 1, 1978). It averaged zero real change between 1980 and 2000; real prices increased initially and then the system entered a period of declining real costs. Based on this projection of real rate increases, price effects neatly cancel out over the 20-year planning horizon. Nonetheless, since electricity prices may still take many paths in future, it is the implications for planning of the structure of the equation that are important here.

Implications of the Price Sensitivity of Electricity Demand for System Planning

The formal recognition of the sensitivity of the load forecast to the rates Ontario sets adds a new dimension to system planning. The electricity price variable is the only one in the demand equation that is sensitive to Ontario Hydro's own forecast accuracy. In turn, it can contribute to forecast errors when there is an inconsistency between the rates determined at an earlier or later stage of the planning process and the projection of rates used in preparing the load forecast. For instance, a difference in unit costs between the 1979 expansion plan, designed for the 1979 load forecast, and the rates projected for the previous year's expansion plan could, for perhaps the first time, alter the load forecast.

A significant inconsistency between forecast and actual system costs is likely to arise only if the load forecast is revised from one year to the next and there is little flexibility to adjust system costs, or if a forecast error leads to a sustained excess or shortage of capacity, or if there is a sudden shift in cost structure (e.g., a change in construction costs, fuel costs, or interest charges). In such cases, the projection of rate increases used in the load forecast may no longer be valid and could cause forecasted and actual electricity demand to diverge. Once there is an excess or shortfall of capacity, any adjustments to system costs will feed back on demand through the price elasticity and may aggravate the return of the system to equilibrium (i.e., to the desired balance between load and installed capacity). Designing the feedback loop into the planning process may be warranted for the 1990s when an over-forecast of demand could lead to excess nuclear capacity or costly deferrals of nuclear units. The effect may be demonstrated, however, in the following somewhat theoretical example arising out of the use of the 1978 price projection in the 1979 load forecast.

The 1979 load forecast of average annual growth in demand of 4.0 per cent for 1980-85 was a downward revision from the 5.5 per cent predicted in 1978. Let us assume that capital expenditures on committed facilities, and interest and depreciation on existing facilities, cannot be reduced significantly because of long planning lead times, and that there are fuel savings but no offsetting cost reductions from operating the surplus units. By 1985, the reduction in the load forecast would result in 7.4 per cent more capacity being in place than is needed and in another increase of roughly 5 per cent in the unit cost of energy. The feedback effect is the impact of the additional rate increase, which was not included in the load forecast. It could reduce demand by another 3 per cent by 1985, which would in itself add a little to the rates, and so on.

In practice, there are several ways for Ontario Hydro to reduce costs in the short run as the load forecast is revised or when load growth falls below expectations. These have been illustrated in the last few years. They include: postponing expenditures on the uncommitted expansion programme; raising revenue through export sales of power to the extent feasible; increasing the revenue raised through debt; and, as a last resort, deferring or cancelling committed stations. The transition to nuclear power complements these measures to reduce costs for the next few years by offering savings in system costs as fossil-fuelled, and particularly oil-fired, units are displaced. The conditions in the 1980s will probably offer Hydro enough flexibility that a system-planning simulation process that dynamically integrates the first (load forecast) and the last (rate-setting) stages would not be worth the effort.

For the longer term, however, Ontario Hydro's once-through System Expansion Program Reassessment (SEPR)[6] framework would benefit from the taking into account of the impact of system costs on demand. It is not realistic to expect that demand for electricity will remain fixed at a given load-forecast projection while the other major system parameters are varied. The nuclear mix, the reliability level, and the debt ratio (affected by capital constraints and other financial policies) all have a direct impact on the revenue that is raised through rates, and hence on load growth.

The development of a closed-loop-system planning model that links expected demand, system planning, and the financial forecast, and then revises the following year's load forecast in the light of the

calculated rates, may be warranted. Such a model would also be useful in assessing the financial implications of attempting to achieve a particular market share for electricity in the context of a provincial energy strategy. If the target growth rate for electricity demand deviated from Ontario Hydro's load forecast, either the increased debt issues required or the surplus revenue generated in the course of influencing energy consumption patterns through pricing policy would be valuable inputs to the formulation of energy or financial policy.

Ontario Hydro's Cost Structure

Ontario Hydro's rate structure evolved over a long period in which electricity supply was, for the most part, a declining cost industry. This meant that promoting the use of electricity led to a lower unit energy cost system. As Hydro has noted: "Generally, as the size of the utility increased the unit cost of production and supply decreased."[7]

The last time Ontario Hydro's unit generating costs rose was in the early 1950s. Hydro was a purely hydraulic electricity system until the first coal-fired unit came into service in 1951. Coinciding with the commissioning of the Hearn and Keith plants in 1951-3, average electricity costs rose 10 per cent in real terms (to a level roughly equal to 1978 rates in constant dollars). The penetration of coal-fired generation kept rates high in the mid 1950s. Then, aided by the declining real cost of coal, Hydro's total costs began to decline steadily. The nominal price of coal to Hydro was essentially constant throughout the 1960s – about $8.90 per tonne[8] – and fossil-steam capacity, almost totally coal-fired, grew five-fold. Hydraulic resources as a proportion of December dependable peak (excluding purchases) fell from 82 per cent in 1960 to 46 per cent by 1970.

Between the mid 1950s and the late 1960s, Ontario Hydro planners were well aware of the price/demand spiral. Lower rates could be counted on to stimulate demand. Meeting that demand with new generating capacity would reduce average real costs and allow further real rate decreases. The declining block-rate structure, and advertising, added impetus to the growth in sales to assist the utility in taking advantage of the increasing economies of scale. There was little fear of overexpansion; in fact, the combined forces stimulating consumption were, if anything, too successful. Demand was substantially underpredicted for the second half of the 1960s. Reserve margins were severely stretched from 1966 to 1970, and in 1966-7 dependable peak generation resources were actually less than December demand.

The decline in Ontario Hydro's unit energy costs came to a halt in 1970 as the price of coal began to rise in real terms. By 1973, Hydro's real expenditures per tonne for coal were up 16 per cent, and since the jump in international oil prices, they have increased by another 60 per cent. The unit cost of Hydro's purchases of oil has increased more dramatically, approximately doubling in real terms.

The real cost of running fossil-fuelled stations in the 1970s has led the bulk power system into a period of increasing average costs. However, the need for rate increases has been moderated by the availability of significant quantities of power generated by hydraulic and nuclear stations whose costs have been largely unaffected by higher fossil-fuel prices. There is, as a result, a widening gap in unit energy costs emerging between the fossil stations, on the one hand, and the nuclear and hydraulic stations, on the other. This disparity cannot be reflected in the existing average cost-based rate structure. It would now appear to be logical to design a rate structure that gives customers an incentive to reduce the consumption of electricity which would be supplied by an increment in fossil-fuelled generation.

Implementing a change in rate structure was never easy, and at this time it presents two added complications. The first is that the nuclear:coal generation mix will be changing rapidly over the next 10 years or so, until Ontario Hydro attains its target mix. This may oblige the rate-maker to look at the structure of costs beyond this period, for stable pricing guidelines.

The second complication arises out of the excess capacity of fossil-fuelled generating capacity, which could persist throughout the 1980s. Since supply capability (taking required reserves into account) is not at present in balance with demand, the generating system is said to be out of equilibrium. The impact on pricing of the existence of surplus fossil-fuelled capacity is to reduce the increment to the unit energy cost of an additional unit of demand by temporarily eliminating the additional capital cost component. This *lowers* the short-run economic cost of utilizing fossil-fuelled units. Ironically, the surplus capacity is, in part, a product of the general demand-depressing effects of *higher* fossil-fuel prices. Once the system returns to equilibrium, the short-run incremental cost of fossil-fuelled generation will shoot up again, and be more in line with the trend in the cost of the fuel. From today's

perspective, the unit capital cost plus the projected unit fuel cost represents the long-run incremental cost of fossil-fuelled power. The discrepancy between the short- and long-run incremental costs will persist until excess capacity is absorbed.

Appendix B examines the relative economics of new nuclear stations and existing coal-fired stations to see how the movement towards the target nuclear:coal mix is affected by excess capacity. It concludes that existing fossil stations are not obsolete but that, once roughly one-quarter of a nuclear station's capital costs have been committed and spent, there is a benefit to completing the station on schedule, even if it displaces coal-fired units. There does not, however, appear to be a clear-cut benefit-cost advantage to advancing the in-service dates of nuclear units after Bruce B for the purpose of replacing existing coal stations. These results suggest that excess fossil-fuelled capacity will be eliminated by 1990 for a wide range of load-growth scenarios.

Changing Generation Mix

With the commissioning of Pickering A in 1971-3, Ontario Hydro entered a transition phase during which CANDU nuclear stations are expected to be integrated into the generating system until they have taken up the share of the load they may cost-effectively and operationally meet. Present CANDU nuclear reactors have not been designed for load-following capability. They are not capable of functioning in a peaking mode, even if costs could be recovered on the basis of the reduced number of operating hours. This is in strong contrast to fossil and most hydraulic generation sources. Hydro's system planning practices, as described in its May 1976 "Generation Planning Processes Memorandum" to the RCEPP and in testimony during the hearings, indicate that the minimum annual capacity factor (ACF) that is planned for nuclear units is 55 per cent. According to Hydro definitions, this ACF is the boundary between base and intermediate load.

A station that is so placed in the stacking order that it has an ACF of 55 per cent meets a load that is roughly 65 per cent of the annual peak. This corresponds to the minimum load on the year's peak day, a weekday some time between December and March (increased temperature sensitivity due to greater electric space-heating loads makes the precise month less predictable now). Thus, when the point is reached that hydraulic and nuclear are serving the entire base load, nuclear stations may be said to be "on the margin" of the winter off-peak load. An increase in the winter night-time percentage of the peak will most likely be met by an intermediate load station that is coal-fired.

Should the 1979 load forecast for 1990 be correct, Darlington would have an ACF of slightly more than 55 per cent. However, if Darlington were kept on schedule and load-growth rates fell to an average of roughly 3.5-4.0 per cent between now and 1990, Ontario Hydro could meet all base loads with its nuclear and hydraulic stations. Even lower load growth would advance the date when this is possible by a few years, but it is fairly safe to say that it will not be until the late 1980s or early 1990s that the nuclear component reaches its target share of system capacity. This implies that during the 1980s increments to off-peak demand in winter will be served by coal-fired capacity. During the other seasons there will be some opportunity to substitute nuclear for coal-fired power, were a new rate structure to motivate a shift in the patterns of electricity consumption from peak to off-peak hours.

Utilizing Excess Capacity in the 1980s

Pricing to encourage the utilization of excess capacity poses problems for any capital-intensive (high-fixed-cost) business whose product is demand-inelastic. These characteristics commonly apply to public enterprises such as public transportation, the post office, and electricity utilities. The demand for a commodity is said to be inelastic if a percentage decrease in price leads to a less than proportional increase in demand, i.e., if its elasticity lies between -1.0 and 0.0. The estimates of the price-elasticity of aggregate provincial demand for electricity range widely, but invariably they are within this range. (Ontario Hydro's estimate of long-run elasticity in the 1979 Load Forecast Memorandum was -0.63.) When demand is inelastic, a decrease in price is not offset by the resulting increase in sales, so that revenue (the product of average rates and the quantity of energy sold) falls below what it might otherwise have been. This poses problems for the use of pricing policy to stimulate Hydro's primary sales. In the 1960s, real costs fell with increments in demand. Under the present circumstances, it will be extremely difficult for Hydro to reduce the cost of a unit of energy as it sells power from surplus units. Following current principles of rate design, a price-induced stimulus to the demand for electricity would probably lead to a reduction in Hydro's net income.

One way to reduce costs that are normally covered annually through the revenue from rates would be

not to levy charges for the capital cost of surplus stations. This could be implemented, in practice, by postponing the depreciation charges on these stations, but it would mean issuing additional debt to finance interest payments and debt retirement. Later on, capacity charges would have to be increased to above the level where they might otherwise be, to retire the extra debt. Another way to promote the use of excess capacity emerges if an incremental cost pricing scheme is adopted. Eliminating the capacity charge in peak-time rates when there is excess capacity is consistent with short-run incremental cost pricing principles for electricity. However, adopting a short-run incremental cost rate structure would not help to stimulate demand for electricity in Ontario unless the charge for peak energy was less than the current average rate level. As it happens, the unit energy charge for most surplus units exceeds the current system average cost, so that pricing to recover the full costs of the marginal surplus units would actually depress the demand.

Ontario Hydro's excess capacity in 1979 was about 3,600 MW above required reserve on the winter peak, and, on the basis of Hydro's 1979 load forecast, it will remain roughly at this level until the mid 1980s as Bruce B comes into service (see Figure 4.1). Surplus stations are, almost by definition, Hydro's most expensive to run, and most of them were intended for a peaking role in the system. The excess capacity consists of 2,200 MW of oil-fired capacity at Lennox, 1,150 MW of dual-purpose gas- and coal-fired capacity at Hearn, and 250 MW of coal-fired capacity at Keith. Currently, oil-fired capacity has fuel costs of about $34 per megawatt hour, gas-fired $29, and coal-fired $15. By the late 1980s, the approximately two-to-one ratio in oil or gas to coal costs could increase to three to one.

Because most of the excess capacity has extremely high running costs, a rate structure that prices peak-time power at its short-run incremental cost (ignoring capacity costs) will mean that the surplus stations' running costs exceed what customers will pay, using the current rate structure. This implies that demand for peaking capacity would fall rather than rise, if pricing policy were the key to selling generation from surplus stations, without incurring losses in operation. Full utilization of surplus coal-fired units is the best that can feasibly be achieved.

During the disequilibrium period and while the nuclear:coal mix converges on its target, encouraging the use of surplus coal-fired peaking capacity means shifting coal combustion from off-peak to peak hours (worsening the system load factor), or, if high load factor demand is encouraged, adding to both peak and off-peak energy consumption. In the first case, Ontario Hydro's costs would likely be indifferent to any induced shift in consumption patterns, because coal capacity will supply marginal increases in both on-peak and off-peak demand. However, total revenues would be seriously curtailed and bad habits would be formed. In the second case, higher total sales would give Ontario citizens the benefit of extra coal capacity in place, though coal imports would be higher than otherwise (unless currently contracted coal could not be sold elsewhere anyway). But this case is similar to the one that arises from a lowering of the average rates in the existing rate structure; some overbuilt capacity may be utilized if capital charges to the customer are postponed or the provincial government absorbs the bill (with the same net effect). The matter of the utilization of excess capacity in the 1980s is therefore not so much one of rate structure as one of financial policy regarding the revenue requirement. If some capital charges were to be postponed in order to increase the sale of power, and additional debt issues were required to achieve this, the question would turn on whether or not the provincial economy would get a satisfactory return on the use of the extra electric energy to justify what amounts to a debt-financed subsidy.

Most of the benefits of utilizing excess peaking capacity are lost because the fuel the stations burn is imported into Ontario. Turning imported coal or oil into electricity for consumption in Ontario, simply because the means to do so exists, achieves little for the province unless the payments for the fuel are neutralized on the provincial balance of trade. This can come about as a result of the substitution of electricity for other imported fossil fuels, whose security of supply may be of more concern, or because the additional electricity sales generate value-added in Ontario that may be exported or substituted for imports. (Value-added, in Ontario, is the value of Ontario resources, labour, and capital that are put into the production of a final good or service.) The latter will not happen if consumers simply concern themselves less about "wasting" electricity, and both may be difficult to achieve if it is clear that the rate "subsidy" will be of limited duration. The major benefit of surplus capacity – higher reliability levels – will accrue to the province regardless of the pricing policy adopted.

Without an increase in value-added in industry in Ontario, or inter-fuel substitution, the best option would be to export the power, rather than to attempt to utilize it domestically. A new rate structure for

Ontario Hydro customers could then concentrate on promoting efficient utilization of the remaining capacity by applying a rate design appropriate for the 1990s.

Long-Run Incremental Costs

There may be little to lose and a lot to be gained by designing rates for the 1980s that reflect the cost structure probable for the 1990s and beyond. After excess peaking capacity is absorbed and nuclear replaces coal on the margin off-peak, Ontario Hydro will enter a period with a cost structure that is unique in its history. Peak energy costs will probably still be escalating in real terms due to continuing real increases in coal prices, while real off-peak energy costs could stabilize. Pricing to reflect the long-run cost structure is important because electricity rates affect investment decisions in electricity consuming systems, which have a much longer life than the period of excess capacity.

As Turvey and Anderson have noted:

> If, for example, additional peak power is expensive, then the tariff should make consumers pay a lot for additions to peak consumption. The tariffs, however, should reflect the expected future cost structure over a whole period of years because consumer reactions to them, almost always involving capital investment, take time.[9]

Thus, discounts to encourage the utilization of the temporary capacity surplus expected in the 1980s could result in the addition of loads that would need to be served by peaking (or, more generally, low ACF) stations well after the excess capacity has been absorbed, thereby perpetuating an over-allocation of resources to electricity supply.

Appendix A analyses the cost of meeting increments to demand in the late 1980s using nuclear and coal-fired generation over a range of annual load factors (ALF). Table A.2, which is explained in Appendix A, shows that at a 65 per cent ALF, roughly the system's annual average, 1 million BTU of electric energy delivered to the point of end use in 1987 from a nuclear station completed in that year would cost roughly $7.60 in 1978 dollars (equivalent to about $44-per-barrel oil if it were utilized with the same efficiency as oil).[10] The same delivered power from a new coal-fired station would be about 15 per cent more expensive. Unit nuclear electricity costs in the late 1980s for a 65 per cent ALF load are about 40 per cent higher in real terms than the average unit price paid by the general (i.e., non-residential) customers of the municipal utilities in the years 1965-72. On the other hand, the incremental unit cost of base-load nuclear-generated electricity is escalating much less rapidly than the market price of fossil fuels in Ontario, so that, where the two compete, electricity will tend to become a more economically attractive fuel.

Electric space heating is usually assumed to have an ALF of about 30 per cent, since it is a fairly continuous load for three to four months in winter. Table A.1 indicates that the incremental unit energy costs in 1987 for a load with these characteristics would be roughly $13 per million BTU in 1978 dollars, whether it was generated by a new coal-fired or a new nuclear station. Assuming a conversion efficiency of 60 per cent from heating oil to space heat, it is estimated that delivered electricity for space heating from a new station in 1987 would cost the equivalent of heating oil priced at $1.25 per gallon in 1978 dollars – roughly double the price of heating oil in 1978. The implications for housing design and for the retrofitting of homes, of charging for electric space heating on the basis of long-run incremental cost, are analysed in the next chapter. They are dramatic. One straightforward way to implement a space-heating rate reflecting marginal costs would be to institute seasonal variations in the block structure. In the winter months the tail rate could be made equal to the incremental cost of meeting the space-heating load.

Because electric space heating is fairly continuous, it is the most desirable form of low-ALF use of electricity from the perspective of a nuclear reactor. Operating constraints limit the use of nuclear power for non-continuous (e.g., daily peaking throughout the year) uses. Low-ALF uses of nuclear power either will not be feasible (i.e., will continue to be met by fossil-fuelled stations) or will remain incrementally quite expensive in comparison with average electricity rates. Conveying to customers in the 1980s the costs Ontario Hydro will incur in meeting such loads in the 1990s may significantly reduce the need for new capacity and motivate users to take steps to lower their long-term energy costs. Nuclear power is not proving to be "too cheap to meter", as frequently promised in the 1950s. The shift in relative prices of fossil fuels has helped to endorse the decision to go nuclear, but its economic advantages have been tempered by the real cost increases experienced by the nuclear programme (including heavy-water plants) and the four-fold real increase in uranium prices. Generalizations

about the low unit cost of nuclear energy are based on the relative performance of nuclear and coal-fired generating stations operating at high ACFs. Certainly, the increasing share of nuclear power in the generation mix reduces the cost of base-load energy in comparison with what it would have been had coal-fired stations been built in place of nuclear. However, nuclear power will only be able to substitute for fossil fuels in end uses that have low ALFs if fossil fuels undergo very substantial real escalation. Nor is nuclear power, even at high ACFs, cheap in comparison with the base-load electricity rates of the 1960s. There is now, and there will still be in 1990, a significant incentive to encourage prudent use of electricity, particularly that generated by fossil-fuelled or low-ACF nuclear units.

Rate Levels and the Rate of Return

The financial policies Ontario Hydro adopts, either within the current accounting cost framework or in a future marginal cost pricing rate design, have a large discretionary component. Their impact on average rate levels could be exploited to encourage or discourage electricity demand by appropriate selection of policies that alter the mix between financing with internally and externally generated funds. Net income, Hydro's annual contribution to the accumulated equity of the corporation, plus the flow of funds from depreciation, are Hydro's sources of internal financing. Debt issues are the sole form of external financing.

The choice of depreciation policy can affect the need for new debt or equity financing to the extent that internally generated funds are accumulated in advance of the need to replace the assets involved. Nonetheless, Ontario Hydro's "straight line remaining life" depreciation policy, in force for new assets since 1971, will be taken as given. It is beyond the scope of this study to assess this method of depreciating assets relative to other methods though its appropriateness in a period of high inflation is open to question. The criteria for determining net income and so the incremental debt/equity ratio are the discretionary elements explored here.

Under Ontario Hydro's existing rate structure, rates are set to produce gross revenue equal to the expected annual accounting costs of the bulk power and retail distribution systems combined with the desired level of net income. In 1979, running expenses such as operation, maintenance, administration, and fuel and power purchases constituted roughly 57 per cent of Hydro's costs. Charges for depreciation were another 12 per cent, interest on outstanding debt 26 per cent and net income 5 per cent. The small share for net income in 1979 belies the potential of financial policy assumptions to alter rate levels.

Ontario Hydro's slogan for its pricing philosophy, "power at cost", has always been somewhat misleading. The utility is required by the Power Corporation Act to appropriate revenue for debt retirement above and beyond its depreciation charges. In its 1979 rate case before the Ontario Energy Board (OEB), a discretionary component of net income in addition to the amount for debt retirement became explicit. Referring to the proposed net income in excess of that required to meet its debt retirement obligations, Hydro commented in its final argument: "This is a discretionary amount . . . and one which was set by the Board of Directors as necessary in its judgement for the preservation of Ontario Hydro's financial soundness."[11]

Ontario Hydro's "Long-Range Financial Forecast, 1979-1999" states:

> The level of net income from 1981 onwards is determined by financial policies which are designed to preserve financial soundness. The primary financial target is to have a debt ratio in the range of 0.80 to 0.82. In order to attain the target range, the interest coverage is set at 1.35 in 1981 and maintained there until 1984. After that, an interest coverage of 1.25 is used to provide a more realistic projection, as this level is sufficient to support the target debt ratio.[12]

As there is a considerable controversy regarding the validity of any particular debt ratio as an indicator of financial soundness for a Crown corporation whose debt is guaranteed by the government, the discretionary element to rate setting, within the power at accounting cost framework, is the selection of the target debt ratio and the speed with which it is attained. The OEB decision concluded:

> But there is, in the Board's view, sufficient evidence to lead it to the conclusion that the question of how much Ontario Hydro borrows relative to how much it collects from customers today is an important fiscal policy issue for the Government of Ontario. It is a matter on which the Government should give policy direction. It could specify criteria, as in 1977 and 1978, or impose specific borrowing limits upon Ontario Hydro, as in 1975 and 1976. It is not a matter that should be left either to the mythology and vocabulary of the financial assessment of the borrowings of a privately-owned corporation, or to the standards of just and reasonable rates, including a reasonable return, as indicated by that body of

knowledge known as the "broad principles of public utility rate regulation" which is most applicable in the area of return on equity to privately-owned regulated utilities.[13]

Ontario Hydro's charter appears to give it the freedom, on the one hand, to borrow to the limit of its capital availability to keep rate increases to a minimum, or, on the other hand, to price in keeping with private sector practices so that the socially preferred level of electricity demand is determined by competitive market forces.

A further complication to the calculation of net income in a "power at cost" context has been recognized by Task Force Hydro and in OEB decisions over the years: the economic costs of the debt and equity financing Ontario Hydro uses for its capacity expansion programme may not be adequately reflected in the accounting costs charged. When Hydro employs capital that might have earned a higher return for society in another investment opportunity, there is a cost to society in the form of the additional economic activities foregone. In order that resources are not misallocated to the production of electricity, economists would argue that the "social opportunity cost" (SOC) of capital expenditures on electricity supply should be included as part of the cost of capital to Hydro. The return on net assets (operating assets minus accumulated depreciation) now comprises interest payments on outstanding debt (borrowed at the favourable rates made possible by the provincial guarantee) and the net income determined as above. Attempting to reflect completely the SOC of capital in Hydro's rates would lead to net income being calculated so as to yield a rate of return on net assets (i.e., the return on net assets divided by net assets), which corresponded to that earned in the private sector.

The specification of the rate of return that would efficiently allocate society's resources is in itself a controversial issue. The candidate rates range from the average rate of return in the private sector to the rate of return to comparable individual private-sector corporations – essentially utilities with a similar financial structure. Furthermore, it may not be the case that efficiency in the allocation of resources will be achieved if the full SOC is reflected in rates. The preferred position from the perspective of society as a whole may lie somewhere between accounting costs and economic costs. We will consider the second of these issues first and then demonstrate the implications for Ontario Hydro's rates, were it to model itself on a private, though publicly regulated, utility.

The rate of return on the net value of Ontario Hydro's entire operating assets would change only gradually if there was a shift in the rate of return on its incremental investments. However, it is the rate of return on incremental investment that is a relative measure of the efficiency with which capital is being employed. The rate of return required of an investment in the public sector, such that it would not displace "better" investments in the private sector, is termed the "social discount rate" (SDR). Economists almost universally agree that the correct value of the SDR lies between what is called the "social time preference rate" (STPR) and the SOC of capital introduced above. The STPR measures the relative value of future consumption in terms of current consumption. A good estimate of it is provided by the interest rate on long-term government bonds which is about 3 per cent net of inflation (that is, after the interest rate has been adjusted to take out the effect of inflation). When applied to public-sector investments, the STPR reveals a government preference for projects with long-term benefits that probably would not be undertaken by the private sector.[14]

The SOC of capital measures the relative value of current private investment in terms of current consumption. An approximation of the SOC is derived from estimates of the return to capital in the private sector. In an Economic Council of Canada discussion paper, G.P. Jenkins found that the average private-sector rate of return in Canada between 1965 and 1974 was about 10 per cent net of inflation.[15]

Reconciling the STPR and the SOC is a controversial issue in economics. The two discount rates represent trade-offs in different dimensions. The first affects the distribution of consumption between the present and the future, and the second, the distribution in the present between investment and consumption. The judgemental component of this choice is obvious. Inevitably, selection of the SDR entails judgements about the role of government in furthering the 'public interest'. In a 1964 article in the *Economic Journal*, M.S. Feldstein noted:

> In any case, for public investment decisions we may wish to reject the market-determined evaluation of future consumption in favour of a politically determined social time preference function. We may, in short, wish to replace the weights given to the opinions of individuals by the distribution of income and wealth with other weights, such as those given them in the ballot box.[16]

It is still relevant, however, to inquire whether economists can formulate an objective criterion for the

efficient allocation of capital between the public and private sectors. Economists analyse this question with the help of models of economic growth that grossly simplify the dynamics of the real world. Though the models have become more sophisticated over the years, they stop well short of being able to handle long-term strategy considerations such as the security of energy supply; usually the models do not have a foreign sector at all. Nevertheless, it has become apparent in recent research that no single rule for the SDR can be applied to achieve optimal economic growth. A study by K.J. Arrow and M. Kurz[17] in 1970 concluded that, if a project is largely debt-financed the required rate of return in the public sector is the rate of return on private capital. On the other hand, if taxes or user charges form a large portion of the financing, the STPR is appropriate. A 1978 paper by R.W. Boadway relaxed several key assumptions. It concluded:

> Not surprisingly the required return on public sector capital depends crucially upon the assumptions used. There is no *a priori* reason to argue that the public sector [rate of return] should be either the social time preference rate or the private sector return. The required return depends upon the financing instruments available and upon the underlying structure of the economy.[18]

One can only conclude that the theoretical results do not yet suggest objective guidelines for determining the rate of return to "public-sector investment that is in the 'public interest'". The best that can be said appears to be that the rate of return appropriate for Ontario Hydro's incremental investments will be a blend of the STPR and the SOC of capital peculiar to its sources of financing and the economic context at the time. In practice, there may be no substitute for judgement in selecting the SDR and ultimately the level of rates.

As a result of its practice of basing rates on accounting costs, Hydro has a current rate of return on net assets that is little more than the long-term bond rate (STPR). However, because Hydro has designed its 1979 "Long-term Financial Forecast" to reduce the debt ratio from 0.86 in 1979 to 0.82 in 1983, the rate of return will rise temporarily almost to the equivalent of that earned by a private utility. Subsequently, it returns to a rate just above the STPR. In future, if it was felt that the market forces induced by a rate of return more in line with the private sector would lead to a more desirable level of electricity demand than would evolve from the existing pricing philosophy, Hydro could calculate its net income as if it were a private utility or a typical private corporation.

In keeping with the normative quality of the SDR, modelling Ontario Hydro's rate of return on that earned by representative private utilities has little more economic rationale than selecting any other rate of return on the spectrum between the STPR and the SOC of capital. Certainly, there are practical reasons for not wishing to diverge from electrical industry or other utility practices. Nevertheless, the objective of Ontario Hydro's rate of return is more general than the efficient allocation of resources between a public and a private utility in Ontario. It should help the province to arrive at the most advantageous blend of public and private investment, particularly in the energy sector.

Even though it is a somewhat artificial example, it may be instructive to explore how Ontario Hydro's rates would be affected were it to price as if it were a private utility. The major difference between Ontario Hydro and most investor-owned utilities is the government guarantee of its debt. This gives Hydro two advantages: it allows it to borrow at lower interest rates and it permits it to operate with a much higher debt ratio than it otherwise could. Hydro's access to inexpensive debt has been given a high profile. Several public interest groups have labelled it an implicit subsidy of rates. However, it may be that the impact of the provincial guarantee on Hydro's debt ratio is a more significant factor in keeping rates low. Because of the higher risk to lenders that is associated with the financing of private utilities, their debt ratios are usually in the 0.50 to 0.70 range. In 1975, for example, the four AAA investor-owned utilities in the U.S. had funded debt as a percentage of total assets lying between 47 per cent and 52 per cent. If Hydro wished to operate as if it were a private utility, that is, without the provincial guarantee, it would have to realign its debt ratio. The extent of the adjustment to the debt ratio and the increase in interest rates would both depend on the credit rating Hydro managed to obtain.

A 1975 study carried out for Ontario Hydro commented on Hydro's likely credit rating if it borrowed in its own name without the provincial guarantee and without altering its financial ratios:

> While this is a subjective question, it was nevertheless agreed that Hydro's current financial position, showing a low interest coverage, a high ratio of debt to equity and a low return on equity, would probably result in about a "B" or lower credit rating.[19]

Assuming that such a low rating would not be satisfactory for Ontario Hydro, let us explore the costs of restructuring Hydro as if it were a private utility with a BBB rating. The present debt ratio of 0.86

would need to be reduced to about 0.65. This would require roughly a one-third reduction in total debt. The tripling in accumulated equity that this entails would require additonal net income well in excess of the total revenue of $2.5 billion raised in 1979. The speed of the "transition" would set the pace for rate increases for years. To maintain a debt ratio of 0.65 would require net income of roughly triple the present level.

The increase in interest payments would also be substantial. The differential in the yield on bonds issued by AAA and BBB credits averaged about 1.6 percentage points in 1974-7. The present worth of the corresponding difference in interest charges on a $1.5 billion series of 30-year bond issues, roughly one year's net borrowing by Ontario Hydro, would be about $260 million. Evidently, Hydro's net income would be considerably higher than it is now if it continued to borrow with the provincial guarantee but priced as if it did not. The surplus funds that would result in this case represent the value of the provincial guarantee to electricity consumers.

Envisaging Ontario Hydro transformed so that its financial structure and rate of return on net assets corresponded to that of a private utility may appear to be a somewhat hypothetical exercise, yet it reflects a shift in pricing philosophy from power at accounting cost towards power at economic cost. A more economically defensible approach to pricing electricity as if its value was determined in free market competition, however, would be to adopt a rate structure based on marginal cost pricing (MCP) principles. One of the properties of a full MCP rate structure would be to set the rate of return on Hydro's incremental investments at the SDR.

In its deliberations concerning the costing and pricing of electricity, the Ontario Energy Board debate centred on finding a satisfactory rate structure that would reflect the principles of MCP but constrain revenue collected to the revenue requirement calculated from accounting costs. Revenues collected by an MCP rate structure would only equal the traditional revenue requirement when incremental costs coincided with historical costs. For instance, in a period of rising incremental costs, MCP would be expected to produce a profit relative to accounting costs. Constraining revenues collected under MCP to the accounting cost requirement would depart from efficiency pricing principles, both by ignoring any divergence between incremental and average historical costs and by not necessarily charging rates that reflect the social cost of capital.

Thus, at least three levels of total revenue may be delineated under different versions of MCP. One would be the same as under the existing average cost pricing rate structure, i.e., if the revenue collected was constrained to meet the present requirement. A second would derive the revenue requirement from a modified power-at-cost principle, as discussed above, by incorporating in the cost of power a rate of return on public sector capital equal to the SDR. To the extent that the SDR exceeded the long-term interest rate on government bonds, Ontario Hydro's rates would generate net income surplus to the traditional revenue requirement. A third option, full MCP, would start with the surplus produced in the second case and would add or subtract from it, depending on the relationship between incremental and average historical costs. If, as seems probable, Hydro experiences slowly increasing real costs, the adoption of long-run MCP would tend to increase its revenue surplus.

It appears that, whether the underlying rate structure is based on average or marginal costs, the potential exists for the financial policies that determine net income to be guided by judgement in the form of energy or industrial strategy choices. However, the use of electricity rates to implement broader policy goals has, up to now, been limited by the practical problem of how to handle situations in which Ontario Hydro's revenues depart significantly from accounting costs. The fundamental issue at stake is, whether Hydro should be financially independent of the provincial government in all respects other than the guarantee of its debt, or whether revenue transfers between Hydro and the Ontario Treasury should occur in such cases. Task Force Hydro recommended in 1973 that "surplus funds be retained by Hydro to be used at its discretion for debt retirement, rate stabilization, [and] system expansion and to provide for contingencies".[20] This assigns to Hydro the responsibility for investing any surplus funds in the interest of the people of Ontario. The opposite perspective on surplus funds was expressed by R. Turvey in 1978 in a speech entitled "Revising the Revenue Requirement":

> In other words, you would treat electricity like a money-making public service, in many ways handling it like the non-money-making public service. I don't mean that you would turn all the electricians into civil servants. The point is, in terms of general principle, that the difference between, say, education and electricity would be that electricity is sold at marginal cost and makes money while education is largely given away free and doesn't make money. In either case, the government appoints the people to make the electricity or to do the teaching and, in the case of electricity, it checks

up that prices are rationally founded. In the case of both electricity and education, it checks up that the business is being managed competently. In the case of electricity, where there are profits, the government (that is, the citizens) take them. In circumstances where marginal costs are particularly high in relation to accounting cost, these profits will be big. But what is wrong with this; they belong to the citizens? That, it seems to me, is the right way to handle things and I can't understand why you do not handle it that way.[21]

While pricing electricity as close to its accounting cost as possible does avoid the need to consider a closer financial relationship between the government and Ontario Hydro, it may not be consistent with some energy strategies for Ontario. The issue of revenue tranfers between Ontario Hydro and the Treasury may well be of secondary importance to the pricing of energy in a manner designed to achieve broad energy-strategy goals.

Ontario's other indigenous energy options, conservation and renewables, are of necessity priced incrementally and on a private-sector basis. The Canadian and eventually the international market price of fossil fuels, technically speaking, represents the incremental cost to Ontario of "importing" an additional unit. In this context, a strategy that minimizes the need for government regulation in the energy sector will select a rate of return more in line with full MCP principles. Surplus funds can be directed towards the financing of other energy-related projects, such as public transportation. But this is only one view. Another view might be that electricity consumption in Ontario should be promoted to the maximum extent feasible. As already indicated, either strategy can be accommodated within the broad discretionary freedom that exists in the selection of the rate of return that should be earned by Ontario Hydro. Rate levels, and ultimately the demand for electricity in Ontario, will reflect the judgement made. The selection of Hydro's rate of return is a policy matter for the provincial government to decide when formulating its energy strategy. There is no overwhelming economic rationale for any particular value within the range that has been delineated.

Conclusions

Since 1976, the importance of econometric models of electricity demand in the preparation of the load forecast has increased markedly. Electricity price variables were not included in the 1976 equation, but by 1979 the estimate of the price elasticity of demand implied that in the long run a 10 per cent increase in real rate levels would lead to a 6 per cent decrease in peak demand. The evolution in load forecast methodology has formalized the role of electricity pricing in the long-term system-planning process. The significant feedback of electricity rates on future demand introduces a dynamic element into the system-planning process. The development of a model that closes the cycle that begins with the load forecast and ends with rate-setting may now be warranted, for appraising long-term system planning. Such a model would be vital to estimating the financial implications for the province of attempting to implement a goal-oriented energy strategy.

The dramatic increase in fossil-fuel prices in the mid 1970s brought an end to a long era in which Ontario Hydro had experienced declining real incremental unit energy costs in serving both peak loads and base loads. Until the late 1980s, the electric power system will be in a transitional period in which nuclear plants will meet an increasing share of the total demand but marginal peak and off-peak loads will be served by fossil stations with rising unit energy costs. As the nuclear:fossil generation mix approaches its target ratio around 1990, base-load generation costs are expected to stabilize in real terms at a level roughly 40 per cent higher than the base-load costs of the 1960s. Compared with rises in oil and natural gas prices, the escalation in base-load electricity costs will be modest. However, the unit energy cost of serving daily or seasonal peak loads will continue to escalate. If fossil-fuelled stations serve most of these loads, costs will rise to track coal prices. If some of the peak uses are supplied by nuclear stations, then costs will rise because of the expense of operating nuclear stations at lower and lower annual capacity factors. The incremental cost of supplying a space-heating load with electricity will only become competitive with fossil fuels in equally insulated homes if fossil-fuel prices rise to the equivalent of about $40 per barrel (1978 dollars). This divergence between incremental peak and base-load costs, essentially between the fossil and non-fossil components of the system, is a departure from historical trends that should be reflected in Ontario Hydro's rate design.

The difficult matter of implementing a change in rate structure that improves the economic efficiency with which electricity is utilized while appearing fair to all customers has been before the Ontario Energy Board for over two years. This chapter has addressed two issues in this controversial debate: short-run versus long-run pricing for the period of excess capacity in the 1980s, and the policies that

determine the total revenues raised through rates. Ontario Hydro will probably be able to use some of its excess capacity to make profitable export sales. However, efforts to encourage fuller use of the excess capacity by selecting a rate structure that offers an incentive to peak-time electricity consumption are likely to result in a decrease in revenues relative to costs and hence in greater debt financing than otherwise need have occurred. They would also encourage the addition to the system of long-term loads that would be extremely costly to serve once the temporary period of surplus capacity had passed. Furthermore, utilizing excess capacity simply because it has been built offers little gain to the provincial economy when the fuel is not indigenous to Ontario. Ontario Hydro's payments for fossil fuels imported into the province may most readily be offset by exporting the power they generate. It is therefore argued that the period of excess capacity in the 1980s should not delay the implementation of a more economically efficient marginal cost-based rate design that reflects clear long-run trends in the cost of supplying electric energy.

In a period of rising energy prices, it is not surprising that the issue of efficiency in the allocation of resources to electricity supply has achieved new prominence. Ontario Hydro's incremental capital expenditures may be said to be efficient from the province's perspective if they earn a rate of return that does not displace "better" private sector investment opportunities. However, the selection of the specific rate of return, the social discount rate, that is in the best interests of present and future generations remains a value judgement. Economic theory has delineated a range for the social discount rate. It should normally lie between the interest rate on long-term government bonds (about 3 per cent real) and the rate of return in the private sector (about 10 per cent real). Nonetheless, objective public investment decision rules are still a matter of considerable debate. At the present state of the art, there remains a large discretionary component in the choice of a rate of return for Ontario Hydro.

In the existing average historical or accounting cost-rate structure, the implicit rate of return for Ontario Hydro is manifest in the net income earned and the target debt ratio set. In a marginal cost-pricing framework, the rate of return is reflected in the cost of capital for incremental capacity. In either case, a shift from power at accounting cost towards power at economic cost could make a significant difference to both the structure and the levels of electricity rates, and hence to future electricity demand.

The impact on economic activity in the province of changes in electricity rates and fluctuations in Ontario Hydro's capital spending are sufficiently important that Hydro's financial policies should become the subjects of provincial fiscal and energy policies. These could conflict. An environment in which both the load forecast and one of its major inputs, electricity rates, have considerable judgemental elements strongly suggests a need for long-term energy-strategy goals for the province. Fiscal policy has a much shorter time horizon. The balance between fiscal policy and energy policy objectives represents the same choices that are implicit in the selection of the social discount rate.

Figure 3.1 Average Fuel Prices for Residential Space Heating in Ontario
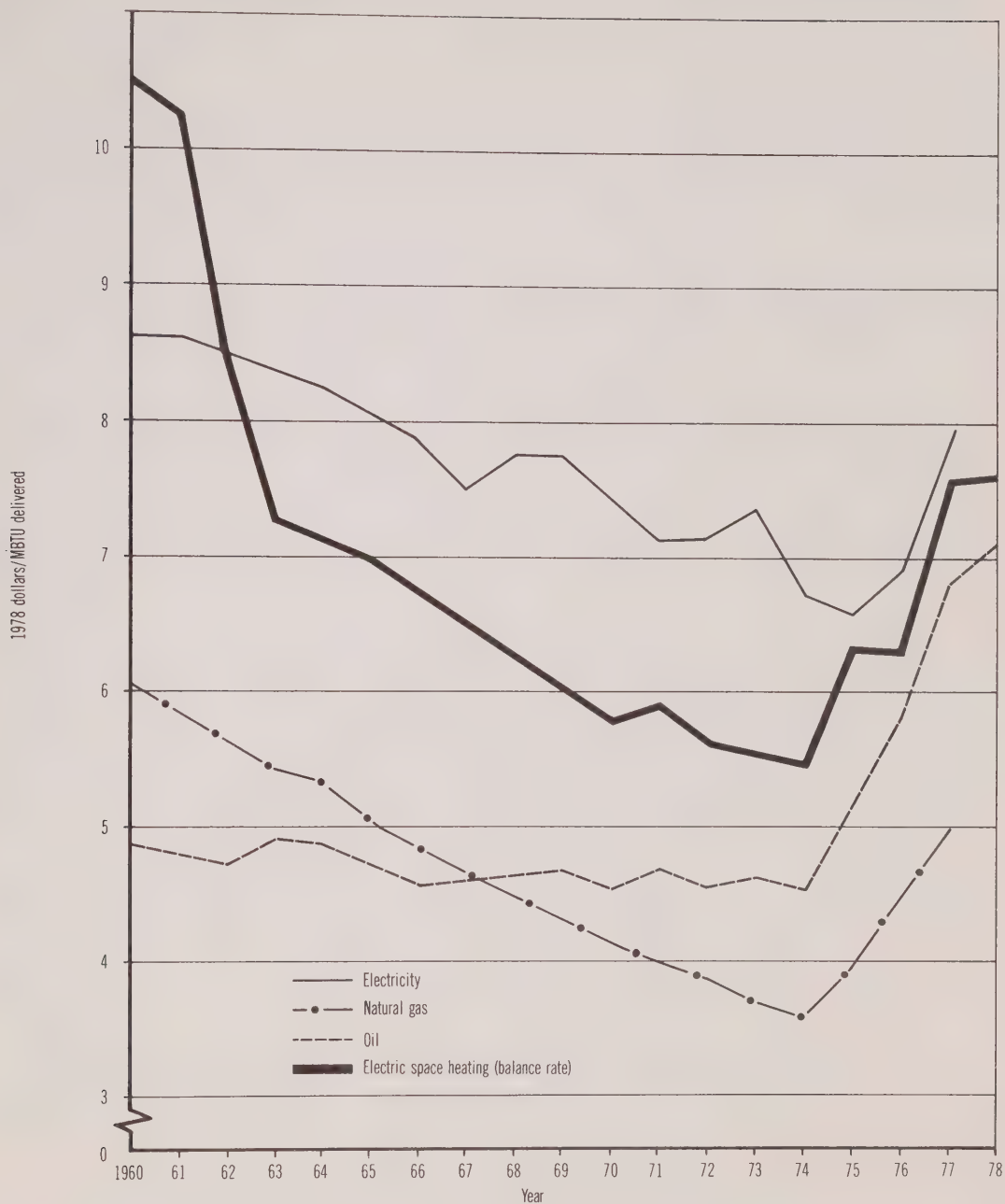
Note: Conversion efficiencies assumed— electricity 100%
                                    — gas   55%
                                    — oil   50%

Sources: Ontario Hydro, Ontario Ministry of Energy,
         Consumers' Gas Company.

Ontario Hydro's Role in the Economic Development of the Province

The expectation that abundant electricity will serve as a catalyst for economic growth in the province is one of the more high profile components of Ontario's industrial strategy. Politicians regularly emphasize the stimulus to the provincial economy provided by the combination of industries that Ontario Hydro purchases from, industries that primarily consume the electricity Hydro generates, and the revenues from export sales of electricity. The first section of this chapter outlines the significance of Hydro's capital expenditures to the province's economy.

The next section reviews the importance of electricity as a factor of production in Ontario and the recent performance of the electricity-intensive industries and their job-creation record. It will point out the competition Ontario faces from other provinces, particularly Quebec, in attracting firms for whom the price of electricity is of paramount importance, and offer brief profiles of the issues currently affecting the location of the most electricity-intensive industries in Ontario.

The final section surveys Ontario's potential export markets for electricity. The possible firm export of major quantities of electricity, while earning revenues for the province, represents a failure of the electricity component of an industrial strategy geared towards attracting industry to Ontario. Nonetheless, U.S. demand for power generated by Ontario Hydro could help to sustain the electricity supply industries. The analysis is not very optimistic about growth in Ontario's export sales in the 1980s beyond the level attained in 1979, and it suggests that the U.S. would be an unlikely supporter of the CANDU programme in the 1990s, whether through direct reactor sales or through long-term, firm power purchases.

Ontario Hydro's Impact on the Provincial Economy

Ontario Hydro's impact on the Ontario economy goes far beyond the supply of electricity. Since the mid 1970s about 10 per cent of the total capital spending in Ontario and over 70 per cent of the capital spending by all levels of government in Ontario has been undertaken by Hydro (see Table 4.1). Ranked by capital assets, Hydro is the largest corporation in Canada.[1] The benefit derived by the province from Hydro's capital expenditures is enhanced by their high Ontario content. Because Hydro is a Crown corporation and plays such an important role in the economic life of the province, it has become one of the most powerful instruments of economic policy open to the Ontario government.

Table 4.1 Relative Size of Ontario Hydro's Capital Spending

Capital Expenditures in Ontario ($ million)	1965	1970	1975	1978
Total public and private	4,378.3	6,927.5	12,920.3	15,570
Utilities[a]	689.9	1,334.1	2,930.6	2,972
Government and institutions	884.2	1,299.7	2,003.4	2,094
Ontario Hydro	150.0	511.0	1,442.0	1,537
Percentage of total	3.4	7.4	11.2	9.9
Percentage of utilities	21.7	38.3	49.2	51.7
Percentage of government and institutions	17.0	39.3	72.0	73.4

Note a) Including outlays on heavy-water plants ($250 million in 1975, $254 million in 1978).
Sources: Statistics Canada and Ontario Hydro.

Ontario Hydro's Capital Expenditures

In 1965 Ontario Hydro's share of total investment in Ontario was 3.4 per cent. With system capacity requirements doubling every decade, Hydro's spending for generating capacity, now fossil and nuclear rather than hydraulic, grew at an average annual rate of 25 per cent between 1965 and 1975 compared with 11 per cent for aggregate investment in the Province (see Table 4.1). Hydro's expenditures escalated dramatically in dollar terms from 1974 to 1975, precipitating the imposition of borrowing constraints. After 1975 they levelled off in the face of a scaled-down system expansion programme. The significant increase in foreign borrowing by the provincial government on behalf of Hydro in 1975

helped to sustain economic activity in Ontario in a year in which most of Ontario's trading partners experienced a strong recession.

The dynamic increase in Ontario Hydro's share of provincial investment activity has been more than matched by the growth of its share of government capital spending. In the mid 1960s, when construction of hospitals, universities, roads, and public buildings was booming, Hydro's capital expenditures comprised 17 per cent of the total spending by all levels of government in the province. As these capital projects declined, Hydro's expansion programme increasingly dominated public sector capital spending. If the policy of restraint affecting most aspects of government spending continues, Hydro will likely maintain its current share of nearly three-quarters of public sector capital spending in Ontario. Its proportion of total provincial capital expenditures may decline in the 1980s as the expansion programme slows down to adjust to lower load forecasts.

Ontario Content[2] of Ontario Hydro's Capital Expenditures

Ontario Hydro's expenditures are typically distributed as follows: about one-quarter on services, including Hydro design and support staff, consultants, etc.; one-quarter for construction labour; one-quarter on orders for the fabricated metal products industry; one-eighth for electrical industrial equipment; and the remainder for other manufactured materials.

The one-half of total expenditures directed to the purchase of labour and consulting services may be assumed to have nearly 100 per cent Ontario content since the spending is mainly in the form of wages, salaries, and fees paid to residents of the province. Ontario Hydro purchases its machinery and equipment from industries that have a high Ontario content relative to the manufacturing average. Value-added in Ontario as a percentage of shipment value is in the 55 to 65 per cent range for the metal fabrication and electrical equipment industries Hydro orders from, and considerably above the provincial average of 40 per cent in the manufacturing sector. Hydro publishes a summary of its "Total Purchase Value by Point of Manufacture" annually. These records indicate that between 1973 and 1976 the distribution of Hydro's capital goods expenditures was as follows: Ontario 66 per cent, other provinces 12 per cent, and foreign countries 22 per cent. In the future, because of the higher proportion of nuclear expenditures, the Ontario content values for 1976-7 of about 72 per cent of total spending may be more relevant.

Combining the expenditures for labour services and capital goods results in an estimated 85 per cent Ontario content for Ontario Hydro expenditures on system expansion. This figure corresponds closely to that derived by Leonard and Partners in their study, the "Economic Impact of the Nuclear Industry in Canada". Ontario Hydro's high Ontario content means that a unit increase in its expenditures may stimulate the Ontario economy more directly than an increase in consumer spending through taxes cut by the same amount. If there is a discretionary component to Hydro's expansion programme, it becomes a potent lever for economic stabilization and development.

The discussion of Ontario Hydro's Ontario content suggests an important parameter relevant to the debate concerning the provincial job-creation potential of expenditures on nuclear versus alternative energy sources. It is introduced here, though the main treatment of this topic is in Chapter 6. High Ontario content of expenditures on goods and services implies that a large proportion of the payments to personnel directly and indirectly involved in supplying and installing the capital item remain in the province and so bring about greater induced employment when the income earned is spent. When a higher proportion of expenditures is for labour services, this will tend to increase the Ontario content.

The Economic Impact of Ontario Hydro's Capital Expenditures

When the level of annual investment by the private or public sector in Ontario increases, the impact on the provincial economy exceeds the direct value of goods and services purchased. The effect of the extra expenditure is amplified by the linkages between industries and the circulation of the earned income. As we have seen, Ontario Hydro's expansion programme accounts for a significant proportion of total annual investment in the province, and each dollar expended has a high Ontario content. A change in Hydro's capital expenditures is often of interest as much for its economic impact on the province as for its implications for the energy supply/demand balance.

The most commonly used indicators of the economy-wide impact are changes in provincial output (GPP) and total man-years of employment. Several results from the large statistical models of the economy that have been used to estimate the effects that may be attributed to an alteration in the

capacity expansion programme are discussed below. Later on in this section it is noted that in the analysis of policy options these estimates should be viewed in the context of alternative investments, rather than in isolation, and should take into account the capacity utilization rate of the relevant industries.

A $1 billion investment will contribute a multiple of that amount to provincial output. Because macro-economic models of the Ontario economy are in an early stage of development due to data limitations, it is difficult to obtain credible estimates of output multipliers for Ontario. However, national estimates should be a close approximation of them. Several Canadian models, including the Statistics Canada input-output model and the University of Toronto's TRACE model, generate output multipliers for Canadian electricity sector expenditures of between 1.4 and 1.5. This means that eventually the initial $1 billion invested will induce an increase in GPP of $1.4 to $1.5 billion. Macro-economic models indicate that most of the impact occurs within three to five years, with about 60 per cent in the first year.

The interprovincial input-output model of the Department of Regional Economic Expansion has been adapted to produce provincial employment impact estimates. Leonard and Partners[3] applied the DREE employment impact multipliers to the results of their survey of employment in the design, manufacture, and construction of nuclear stations and heavy-water plants. They estimated that $1.2 billion of expenditures in 1977 resulted in 57,400 man-years of direct and induced employment in Ontario. Since the nuclear programme dominates Ontario Hydro's capital expenditures, this would imply that about 48,000 man-years of employment are associated with $1 billion (1977 dollars) of Hydro spending. Roughly the same total employment effect per $1 billion (1977 dollars) may be inferred from Ontario Hydro's calculations in its 1979 "Review of Generation Expansion Program" (Chapter 16) and from Statistics Canada's input-output model.

Statistical estimates of output and, particularly, employment impact, such as the ones presented above, are quoted frequently but they should be qualified carefully.

When capital resources are available, alternative investments outside Ontario Hydro could probably be made. The net employment effect is really the result of choosing one option over another and is measured by the difference in the total-impact estimates. Rarely would investments truly arise in isolation. However, because energy projects have many similar characteristics at the level of aggregation at which they are perceived by an economy-wide model, output and employment impacts may not be very helpful in choosing *between* projects of equal cost and regional content. This sometimes tempts governments to favour a large investment over a smaller, relatively more cost-effective one, because more employment appears to be created.

Furthermore, impact multipliers derived from an economic model use an average effect to approximate an incremental one. The last $100 million spent may not have the impact typical of the first few hundred million. The incremental effect will be quite sensitive to the degree of slack in the relevant industries, a factor not taken into account by the model. A firm with considerable over-capacity will not hire as many people or purchase as much new equipment to fill an order as one already operating at full capacity. On the other hand, a firm about to close shop may stay in business because of an extra sale. As a result, the impact of incremental Ontario Hydro expenditures on Ontario's economy will be quite sensitive to factors that only detailed, firm-by-firm investigation can identify.

The Electricity Supply Industry

The two-digit (in the Standard Industrial Classification – SIC) industries most dependent on Ontario Hydro's capital expenditures in 1978 were electrical industrial equipment manufacturers (12 per cent of their output sales), construction (5 per cent), and metal fabricating (3 per cent).[4] This level of aggregation disguises the adjustment problems faced by individual firms when Ontario Hydro stretches out its expansion programme.

Most companies that Ontario Hydro purchases from are sufficiently large and diversified that they could adapt to a contraction in Ontario Hydro's expansion plan without severe consequences, especially given several years' warning. Other companies, particularly those manufacturing uniquely CANDU components for the Nuclear Steam Supply System (NSSS), are almost totally dependent on orders from Hydro. For these companies, it is possible that there is a minimum annual reactor order level below which they will no longer find their nuclear equipment operations viable.

Equipment purchases for the NSSS, the power-generating system (PGS), and the balance of the plant represent about 32 per cent of the total commissioned cost of the Bruce B and Darlington generating

stations. Of this cost component, 65 per cent is estimated to represent nuclear equipment, though not all of this equipment is necessarily unique to the CANDU programme.[5] About 70 per cent of it is produced in Canada. One may therefore conclude that components from the nuclear supply industries in Canada that are heavily dependent on Ontario Hydro's orders constitute about 15 per cent of the commissioned cost of a nuclear station. In the case of Darlington (4×850 MW), this amounts to about $500 million (1979 dollars) worth of orders spread out over about seven years.

The proportion of total cost is, nonetheless, sufficiently small that building nuclear plants faster than the rate justified by the expected market for electricity would prove to be an extremely expensive way to sustain the CANDU equipment industries. Stockpiling components or making "stand-by" payments would not entail the premature expenditure of most of the remaining 85 per cent of commissioning cost.

The RCEPP's Interim Report, *A Race Against Time*, highlighted the finding by the Leonard and Partners study (undertaken for the Canadian Nuclear Association) that the minimum order range required to sustain a Canadian capability to maufacture critical nuclear station components was between 1.5 and 2.0 reactors (850 MW units) per year. Ontario Hydro's 1979 expansion programme delays generating station E-15 by four years and stretches out Bruce B and Darlington so that orders average one reactor per year for the years 1982-94. Hydro expects that with some rationalization of suppliers, its steady though limited demand, augmented by other domestic and export sales made by Atomic Energy of Canada Limited (AECL), would be sufficient to sustain the industry in Canada. However, should load growth in Ontario average less than 3.0-3.5 per cent per annum to the year 2000, no additional nuclear units would be needed after Darlington until the turn of the century. This could cause a gap in Hydro's reactor orders, which would leave the survival of the industry entirely dependent on orders coming from outside the province. The nuclear industry is also vulnerable if AECL does not succeed in selling CANDU reactors abroad at the rate needed to close the order gap. AECL's contribution to the maintenance of a viable nuclear industry is about one reactor order per year over and above Hydro's requirements for its 1979 expansion programme. The loss of sales to Argentina and Japan suggests that AECL may continue to have difficulty marketing CANDU reactors abroad.

A sharp deterioration in the capability to produce CANDU components in Canada would considerably increase the cost of later reactors and diminish the economic and security-of-supply advantages of nuclear power in Ontario. The uncertainty associated with this threat to self-sufficiency in nuclear power, the potential loss of the CANDU technology and expertise that the nuclear industry has developed, the high Ontario content of capital expenditures in the nuclear sector, and the current prominence of these expenditures in the capital spending undertaken by the province have led to a proposal for entire industrial strategies for Ontario centred around Hydro's expenditures on nuclear power. It should be noted that energy policy could, by itself, stimulate the demand for electricity in Ontario by acting to alter the relative price of fuels. However, the remainder of the chapter examines some of the issues that arise when the provincial industrial strategy and electricity exports are used to augment the demand for electricity generated by CANDU reactors.

Summary and Conclusions

Where there is a discretionary element in Ontario Hydro's expansion plans, the utility's capital expenditures provide an attractive instrument of fiscal policy. Hydro's capital spending constitutes about 75 per cent of the public investment and 10 per cent of the total investment that takes place annually in the province and is thus on a scale that permits the injection of significant sums into the Ontario economy. The high Ontario content of this spending (about 85 per cent) allows a larger proportion of the economic benefits of the stimulus to be retained in the province than almost any fiscal policy measure now open to the provincial government. Hydro's ability to borrow in international markets with the provincial guarantee draws capital to the province without additional deficit financing appearing on the government's balance sheet. In recent years, expenditures on the Wesleyville and Atikokan generating stations and Bruce Heavy Water Plant D were probably continued beyond the point strictly justified by the criterion of supplying power "at least feasible cost" for purposes of economic stabilization.

In the existing institutional framework, the scale, momentum, and self-financing capability of Ontario Hydro's capacity expansion programme give it advantages as a tool of fiscal policy over alternative energy sector investments. Renewable energy and conservation programmes would have at least the same degree of Ontario content and the same impact on employment, per dollar expended, as

expenditures by Hydro, but the institutional structure that might enable such investments to substitute for discretionary electric power projects is lacking at present. The existing government agency that appears to have the greatest potential to fund fiscal policy initiatives in this area is the Ontario Energy Corporation. Without a mechanism for financing other types of energy investments with provincial debt, the estimated GPP and employment impacts of Hydro spending would not be matched by any that could be expected to come from energy sector alternatives.

The extent to which the viability of the Canadian nuclear industry should influence the planning of the electric power system in Ontario has become a serious issue. In the expansion programme that accompanied the 1979 Load Forecast, Ontario Hydro's reactor orders were reduced to an average of one per year between 1982 and 1994. An even lower load growth would result, in the absence of additional sales to other provinces or abroad, in a gap in orders that could cause firms to leave the nuclear industry. The negative consequences would include a smaller Ontario content of CANDU reactors, reduced security of supply, a higher cost of custom-fabricated components, dislocation of highly skilled manpower, and, possibly, longer lead times. On the other hand, there is a consensus that the building of a nuclear generating station without some assurance of a demand for the power, in Ontario or in export markets, is too costly to contemplate. The stockpiling of critical components offers a cheaper, but only partial, solution. The debate will intensify and should be kept out in the open. It is recommended that the outlook for the nuclear industry not be factored into the preparation of the load forecast without the explicit acknowledgement that it is a discretionary component of a broader energy or industrial strategy.

Electricity and Industrial Location in Ontario

The reliability and the cost of electricity supply are certainly two of the factors businessmen consider in selecting the site for a new plant, but they probably rank behind proximity to markets, unit labour costs and labour force skills, tax and tariff structures, and availability of raw materials. Only for a very few industries, for whom electricity is a major cost component in production, will the differential in electricity rates from one jurisdiction to another outweigh cost differentials in these other locational factors.

Table 4.2 lists 18 factors most often selected by businessmen in New York State as important in locating their firms. The survey by Cornell University was made in 1976, so energy factors may not

Table 4.2 The 18 Factors Most Often Selected by Businessmen as Most Important in Locating a Firm (each of 318 respondents listed up to five factors)

Factors	Number of times listed and order of listing						Weighted total[a]
	Total	1st	2nd	3rd	4th	5th	
Supply of skilled labour	120	82	14	7	10	7	514
Proximity to markets	80	25	13	14	16	12	263
Productivity of labour force	77	11	29	24	6	7	262
Supply of unskilled labour	68	20	32	4	9	3	261
Level of state individual income tax	62	13	10	13	15	11	185
Level of wages/benefits	61	11	16	21	11	2	206[b]
Level of state corporate income tax	52	5	7	9	15	16	126
Attitude of organized labour	48	4	15	12	11	6	144[b]
Attitude of state government leaders	48	11	8	4	9	16	133[b]
Access to truck transportation	40	4	5	12	8	11	103
Proximity to raw materials or supplies	38	7	7	11	8	5	117[b]
Attitude of state legislators	29	10	4	4	3	8	92
Level of local property tax	29	3	3	4	12	7	70
Level of state corporate franchise tax	27	4	6	7	7	3	82
Availability of state financial incentives	27	3	5	5	5	9	69
Attitude of local government leaders	27	2	6	2	6	11	63
State unemployment insurance laws	26	7	8	5	5	1	93[b]
Level of county or city sales tax	26	3	1	6	5	11	69

Notes:
a) In weighted total, extra weight is given to item depending on order listed by the respondent. If listed first, each mention is given a value of 5; for second, 4; for third, 3; for fourth, 2; for fifth, 1.
b) If weighted total is used for ranking, these items move up in rating.
Source: F.F. Foltman, "Business Climate in New York State: Perceptions of Labor and Management Officials" (Ithaca, N.Y.: New York State School for Industrial and Labor Relations, March 1976), p. 11.

have registered their full impact (energy was one of 58 factors). Proximity to raw materials and supplies, the only resource factor selected, ranks eleventh.

Only seven of the more specialized industries in Ontario (at the three-digit SIC level) spend more than 2 per cent of the value of goods they ship on electricity (see Table 4.3). The average for manufacturing in the province is 0.7 per cent. Industrial electricity rates in Quebec, one of the lowest-cost suppliers of electricity to industry in North America, are unlikely to undercut Ontario by more than about 50 per cent over the planning horizon. There are numerous reliable utilities in North America whose rates are less than 50 per cent higher than those in Ontario. Within this band, for most industries, the choice of an electricity utility will make a difference of less than 1 per cent to output price. By the same token, only a few industries already operating in Ontario are likely to find shifts in relative electricity prices a sufficient reason to relocate.

Table 4.3 Electricity Consumption in Manufacturing Industries – the 10 Most Electricity-Intensive Industries (ranked by percentage of shipments of own manufacture)

SIC Code	Industry	Electricity expenditures as a percentage of shipments[a]	Percentage of total manufacturing use of electricity[b]	Index of electricity consumption per employee[c]	Employment as a percentage of total in manufacturing
357	Abrasives	7.6	2.2	11.3	0.2
295	Smelting and refining	5.7	5.1	5.3	1.3
352	Cement	5.2	1.9	14.6	0.2
271	Pulp and paper	4.0	13.0	6.1	2.5
378	Industrial chemicals	2.8	10.3	8.4	1.5
358	Lime	2.4	0.2	4.1	0.04
294	Iron foundries	2.0	1.6	1.6	0.8
291	Iron and steel	1.7	12.9	3.1	4.7
183	Man-made fibres	1.7	1.8	1.9	1.1
351	Clay products	1.6	0.4	1.0	0.3
	Total		49.4		12.6

Notes:

a) Provincial average for all manufacturing in 1976 was 0.76%; for the 10 most electricity-intensive industries it was 2.7%; the non-electricity-intensive group averaged 0.45%.

b) Expenditures on electricity as a percentage of total manufacturing expenditures on electricity.

c) The index is calculated as the ratio of kW·h per employee divided by the provincial manufacturing average of 30,655 kW·h per employee in 1976.

Source: "Consumption of Fuel and Electricity by Ontario Manufacturing Industries – Report for 1976". Ontario Ministry of Treasury and Economics, January 1979.

The electricity-intensive subsector, viewed as those industries for whom electricity costs as a share of value of shipments is greater than 2 per cent (an admittedly arbitrary cut-off point), purchases 40 per cent of the electricity consumed in manufacturing in Ontario. Employment in this subsector has not grown as fast as in the rest of the manufacturing sector since the early 1960s.

In 1976, the seven most electricity-intensive industries had nearly the same number of employees that they did in 1965. Their share of total manufacturing employment contracted from 7.2 per cent in 1965 to 6.5 per cent in 1976. This is probably explained by a mixture of relatively rapid productivity growth and relatively slow output growth, since value-added in electricity-intensive industries has not kept pace with the manufacturing sector average.

Table 4.4 compares employment and value-added data for the electricity-intensive industries in 1976 (the latest year for which data is available) and 1965. Similar results would be found for any earlier years in the 1970s. Employment had minor peaks in 1971 and 1974, but in neither case exceeded the 1965 level by as much as 2 per cent. The average annual growth rate in value-added since 1965 for these electricity-intensive industries came closest to that for manufacturing as a whole in 1974, when it averaged 9.7 per cent, compared with the total sector's 10.0 per cent. The relative decline of value-added and employment in electricity-intensive industries in Ontario appears to have begun before the downturn in the economy that followed the oil crisis of 1973.

Table 4.4 Employment and Value-Added in the 10 Most Electricity-Intensive Manufacturing Industries (ranked by percentage of shipments as in Table 4.3)

SIC Code	Industry	Employment			Value-added ($000)		
		1965	1976	Average annual growth rate[a] (%)	1965	1976	Average annual growth rate[a](%)
357	Abrasives	2,467	2,110	−1.4	27,588	47,879	5.1
295	Smelting and refining	11,260	10,871	−0.3	88,635	218,000	8.5
352	Cement	1,163	1,352	1.4	36,234	80,832	7.6
271	Pulp and paper	21,038	21,643	0.3	289,938	540,709	5.8
378	Industrial chemicals	11,106	12,544	1.1	230,341	581,438	8.8
358	Lime	373	366	−0.2	5,887	15,617	9.3
294	Iron foundries	8,533	6,902	−1.9	66,830	170,002	8.9
	Subtotal	55,940	55,788	0.0	745,453	1,654,477	7.5
291	Iron and steel	34,400	40,315	1.5	556,032	1,231,413	7.5
183	Man-made fibres	n/a[b]	9,140	n/a	n/a[b]	173,166	n/a
351	Clay products	3,029	2,770	−0.8	28,972	60,105	6.9
	Total (excluding man-made fibres)	93,369	98,873	0.5	1,330,457	3,119,161	8.0
	Manufacturing in Ontario	774,428	851,811	0.9	8,422,000	20,362,364	8.4
	Ontario	2,505,000	3,931,000	4.2	22,972,000	75,610,600	11.5

Notes:
a) Average annual growth rate 1965-76.
b) Confidential data prior to 1972.
Source: Statistics Canada Catalogues 31-203, 31-206, 31-213.

In the future, as secure energy supplies become a more significant factor in industrial location decisions, reliable and competitive electricity may be more helpful in attracting industries that depend on this high-quality fuel. It is quite possible, however, that firms that are extremely electricity-intensive will select other parts of Canada or the world, with cheaper power. Also, Ontario may wish to encourage a shift towards a higher proportion of finished products and high-technology manufacturing in the province. These industries will be less sensitive to electricity supply than resource-processing firms.

The job-creating spin-offs of capital expenditures on electricity generating capacity should not be allowed to distract the province from pursuing a balanced, sectorially specific, industrial development policy.

The Electricity-Intensive Subsector

Ideally, one would like to have a unit of measurement for electricity-intensity in order to quantify the importance of payments for electricity and so be able to compare them with all the other costs an industry incurs in Ontario. This unit would reflect the importance assigned to expenditures on electricity in the decision to locate in Ontario. It would be the ratio of expenditures on electricity to a value somewhere between the total value of shipments and the value-added. The latter is basically the return to labour and capital, but it does not include expenditures on intermediate inputs purchased in Ontario, such as electricity. For conceptual ease, this study has adopted the ratio of electricity expenditures to total value of shipments.

Table 4.3 lists the 10 most electricity-intensive, three-digit industries in Ontario, ranked by their expenditures on electricity as a percentage of the value of their shipments. In this subsector, which accounted for 49 per cent of total expenditures by Ontario manufacturers on electricity in 1976, the weighted average of power costs as a percentage of shipments was 2.7 per cent. The comparable average for the remaining manufacturing industries was 0.5 per cent.

The largest purchasers of electricity in Table 4.3 (comprising 43 per cent of the total for manufacturing) are included in the ranking of the 10 major power-consuming industries in the province given in Table 4.5. There are five new entries in Table 4.5 and they represent some of the more dynamic industries in Ontario, providing 60 per cent of the manufacturing jobs associated with the 10 largest users. However, they are decidedly not electricity-intensive, averaging less than the manufacturing sector's overall electricity intensity of 0.8 per cent.

Table 4.5 Electricity Consumption in Manufacturing Industries — the 10 Largest Users, 1976

SIC Code	Industry	Percentage of total manufacturing use[a]	Expenditures as a percentage of shipments	Index of electricity consumption per employee[b]	Employment as a percentage of total in manufacturing
291	Iron and steel	13.0	1.7	3.1	4.7
271	Pulp and paper	12.9	4.0	6.1	2.5
378	Industrial chemicals	10.3	2.8	8.4	1.5
325	Motor vehicle parts and accessories	5.4	0.7	0.9	5.4
295	Smelting and refining	5.1	5.7	5.3	1.3
365	Petroleum refining	3.5	0.6	3.8	1.1
179	Small leather goods	3.0	0.9	2.9	3.5
323	Motor vehicle manufacturing	2.6	0.2	0.5	4.6
357	Abrasives manufacturing	2.2	7.6	11.3	0.2
162	Rubber products	1.9	0.9	0.8	2.1
	Total	59.9			25.8

Notes:

a) Expenditures for electricity as a percentage of total manufacturing expenditures on electricity.

b) Index is calculated as ratio of kW·h/employee for the three-digit industry divided by the provincial manufacturing average of 30,655 kW·h/employee in 1976.

Source: "Consumption of Fuel and Electricity by Ontario Manufacturing Industries — Report for 1976." Ontario Ministry of Treasury and Economics, January 1979.

History of Electricity-Intensive Industrial Development in Ontario

The electricity-intensive subsector in Ontario today is the culmination of a pattern of industrial development established early in this century when the cost of electricity in Ontario was low in comparison with other competitive jurisdictions. Inexpensive and reliable hydroelectric power provided a major incentive for primary and fabricating industry to locate in Ontario. After the private power companies at Niagara Falls were amalgamated into the Hydro Electric Power Commission in 1910, electro-process industries expanded vigorously. There is little doubt that the early priority given to electro-process industries by manufacturers in Ontario was a result of the availability of cheap electricity for the processing of raw materials for export to more industrialized areas. With the rapid changes that have occurred in recent years in energy prices, in tax and tariff policies, and in transportation technology required to ship processed materials and finished goods to markets, there is less consensus about the importance of electricity supply in the location decisions of electricity-intensive industries.

Gunter Schramm, a Canadian economist with the World Bank, writing prior to the oil crisis argued that:

> most, or probably all, of the advantages that our [Canada's] low-cost hydro resources offered to export-oriented electro-process industries in the past by now have disappeared. The locational decisions of most electro-process industries are no longer power- but market-oriented and, as a result, it is unlikely that new aluminum smelters (or other electricity-intensive facilities on the same scale) will be built at potential Arvidas and Kitimats. They will be built in other areas where a large existing manufacturing complex guarantees markets and provides the potential for the installation of the huge atomic or coal-fired power plants that are needed to capture the economies of scale inherent in efficient thermal power generation.[6]

Schramm suggests that the combination of proximity to markets and the efficiency of large thermal stations would overcome the cost advantage of locating at a source of cheap hydraulic power.

Recently, however, Nathaniel V. Davis, chairman of Alcan Aluminum Ltd., maintained that energy will be a more important factor than markets in determining where new aluminum smelters will be located in the future.

> With many of the major consuming markets experiencing problems of availability and cost of energy, those markets which have in the past relied heavily on domestic production are likely to find it desirable to look elsewhere for additional primary supplies. New aluminum smelters will seek out locations which are relatively well-endowed with energy, provided the logistical factors and the political risks for the investor are acceptable.[7]

Alcan's recent decisions to build aluminum smelters in Norway and at Ville de la Baie, Quebec, illustrate the importance of internationally competitive electricity in the choice of locations for new smelters or other world-class electro-process facilities, regardless of the proximity to final markets. As

Ontario's electricity costs will not be competitive with regions still developing hydraulic generation, the province will be obliged to compete by marketing a blend of its advantages, which will include reasonably priced electricity. Tariff and non-tariff barriers restricting access to the world's largest markets militate against locational decisions being made on the basis of competitiveness in single factors of production.

Employment in Electricity-Intensive Industries

The energy-intensive industries, along with the energy-supply industries, are, by nature, extremely capital-intensive, requiring relatively few though well-paid workers to run their complex of machinery and facilities. A 1974 Ford Foundation study, "A Time for Change", found that, in the U.S., the major energy-producing and energy-consuming industries consumed one-third of the total energy, yet they directly provided only 10 per cent of the nation's jobs. Table 4.6 ranks the 10 industries in Ontario that consumed the most electricity per employee in 1976 and shows that they consumed over 50 per cent of the electricity purchased in manufacturing while employing only 13 per cent of the manufacturing work force.

Table 4.6 Electricity Consumption per Employee in Manufacturing Industries — 1976

SIC Code	Industry	Index of electricity consumption per employee	Employment as a percentage of total in manufacturing	Electricity consumption as a percentage of total in manufacturing	Average annual wage
352	Cement	14.6	0.2	1.9	15,882
357	Abrasives	11.3	0.2	2.2	12,087
378	Industrial chemicals	8.4	1.5	10.3	17,375
271	Pulp and paper	6.1	2.5	13.0	14,561
295	Smelting and refining	5.3	1.3	5.1	14,243
358	Lime	4.1	0.04	0.2	12,712
365	Petroleum refining	3.8	1.1	3.5	20,392
291	Iron and steel	3.1	4.7	12.9	16,476
183	Man-made fibres	1.9	1.1	1.8	11,394
294	Iron foundries	1.6	0.8	1.6	13,535
	Total		13.4	52.4	15,629

Note: The average annual wage in these 10 electricity-intensive industries is $15,600. The comparable figure for the total manufacturing sector is $12,900.

Source: "Consumption of Fuel and Electricity by Ontario Manufacturing Industries — Report for 1976". Ontario Ministry of Treasury and Economics, January 1979.

The capital-intensity of specific industries in Ontario is difficult to demonstrate because disaggregated capital stock data is not available, but there is some consensus that the estimates provided for the U.S. by the Conference Board in Canada give a useful indication of capital investment per job in major manufacturing and energy industries (Table 4.7). Electricity utilities and raw materials processing rank high on the list compared with the manufacturing average.

Table 4.7 Capital Investment per Job

Industry	Capital investment per employee ($)
Petroleum	108,000
Public utilities	105,500
Chemicals	41,000
Primary metals	31,000
Stone, clay, glass	24,000
All manufacturing (averages)	19,500
Food and kindred products	18,000
Textile mill production	11,000
Wholesale and retail trade	11,000
Services	9,500
Apparel and other fabricated textiles	5,000

Source: Cited in "Jobs and Energy's Environmentalists for Full Employment, 1977" from the Conference Board in "Canada: Capital Invested, Road Maps of Industry", No. 1799, January 1977.

It has been argued frequently in the "jobs and energy" literature[8] that, since high capital-intensity goes hand in hand with rapid productivity gains, the increased allocation of capital to these sectors

exacerbates the unemployment problem. Hazel Henderson, director of Environmentalists for Full Employment, has suggested that the "productivity index" is really an "automation index" that reflects the loss of jobs in industry due to the substitution of capital and energy for labour in the production process.[9]

On a macro-economic scale, the proposition is that incremental investments in these industries may not be the most cost-effective way simultaneously to create a large number of jobs and solve energy supply problems.

Employment impact will be one of the key factors Ontario considers in choosing which aspects of a modern industrial economy to emphasize in the province. An industrial strategy for Ontario that stresses energy-supply industries, principally the nuclear industry, in order to attract electricity-intensive industries, could be expected, on the basis of the capital-intensity discussion above, to yield a poor pay off in terms of direct (i.e., within the industry) job creation. However, this would not be a complete treatment of the employment question. The analysis of job impact should not stop with the direct jobs created. All industries in an economy are interconnected. Activity in one industry will stimulate employment in the industries that supply its inputs (indirect employment). When the income earned in both direct and indirect employment is spent, the demand for a variety of goods and services creates many more jobs (induced employment). Industries also have forward linkages, that is, they may be critical to the existence of final goods manufacturers or higher technology firms. Before a plant starts operating, its construction creates short-term employment and this leads to orders for machinery and equipment. To follow all these effects through and make valid comparisons is an immense, if not impossible, task.

Economists have only recently begun to examine investments from a job-creation standpoint because it was long accepted that when cost-effective capital expenditures were selected they would ultimately lead to the greatest increase in income and wealth for society and bring with them the highest level of employment. This sort of conclusion was probably valid in a closed system without considerations of income distribution. In the past few years rising unemployment has caused a more careful examination of where the jobs will be created (locally or somewhere else), when they will be created (soon or some time in the future), how long they will last, and who will get them (the currently unemployed or scarce skilled labour).

In analysing the job-creation impact of electricity-intensive industries, the factor that will be most important from Ontario's point of view is how many of the indirect, induced, and spin-off jobs will actually be located in the province. Ontario still imports much of its machinery and equipment and exports a large proportion of semi-fabricated goods for upgrading abroad into end-products. Some electricity-intensive industries may not use local raw materials (e.g., aluminum, iron, petroleum); the most important Ontario input would be the electricity itself. Attracting or keeping electricity-intensive industries will really pay off only if the peripheral employment opportunities, counting for many times the direct employment, are largely retained within the province.

When electricity is Ontario's major contribution to an industry, the indirect benefits to Ontario would flow to the electricity-supply industries. The impact on these industries, including the nuclear components manufacturers, would be significant only if there were continuous and rapid growth in industrial electricity consumption. Individual increments to peak demand would not create sustained employment because of the front-end loading of expenditures on generating capacity. In Ontario, the total industrial demand for electricity (i.e., the total demand of firms with a load greater than 5,000 kW) is now less than the capacity of the Bruce A nuclear station.[10] Nonetheless, consistent with the emphasis on internalizing the benefits of capital-intensive industry, it would be more advantageous to attract industries to Ontario than to export surplus electricity to the U.S.

A complete structural analysis of the role of existing or potential electricity-intensive industries in Ontario's economy is beyond the scope of this study. It is not clear whether the weak direct-job-creation record associated with capital-intensive industries would be offset when the ancillary employment effects within Ontario are included. One may conclude, however, that to reap the full benefits of such industries an industrial strategy should attempt to capture for Ontario as many of the indirect benefits as possible.

Ontario Government Policy Statements on the Role of Electricity in Provincial Industrial Development

Industrial electricity prices in Ontario are among the lowest in North America but they now rank behind Quebec, Manitoba, and several utilities in the U.S. Nonetheless, the differential between Ontario's rates and those of competing jurisdictions is probably not large enough to be the determining factor in most industrial location decisions. Although adequate energy supply is a prerequisite for a healthy industrial economy, an overabundance of generating capacity is unlikely to make a significant contribution to Ontario's industrial development.

Policy statements made by the ministers of Industry and Tourism and the Treasury emphasizing the role electricity plays in industrial development appear to overplay the benefits that could be derived from current and future surpluses when compared with some of the analyses prepared by civil servants in their ministries and by Ontario Hydro for presentation to the Royal Commission on Electric Power Planning, the Select Committee on Hydro Affairs, and the Ontario Energy Board.

The Honourable Frank Miller, Minister of the Treasury and Economics, recently claimed that "Hydro's temporary surplus capacity provides Ontario with a real competitive advantage in attracting industry for which energy cost, and more particularly supply security, are a concern".[11]

The Honourable Larry Grossman, Minister of Industry and Tourism, has argued that surplus generating capacity would be

> ... a key weapon in the province's competition for new industry. Some, the opposition (parties) in particular, talk of dealing with that surplus by stopping the world — by closing or cancelling plants like Darlington or Bruce B. But the Ontario government intends to attract new industry with the power — and the new customers will help pay for the excess capacity. We must not create new unemployment and lose hundreds of jobs by cancelling plants simply to deplete a current surplus.[12]

The early submissions made to the RCEPP by the Ministries of Industry and Tourism and the Treasury in 1976, before the surplus generating capacity issue arose, generally support Mr. Miller's and Mr. Grossman's contentions, although the Treasury report is more neutral in its evaluation of electricity's potential for facilitating industrial development in the province.

The Ministry of Industry and Tourism maintained:

> Security of supply of reliable power is a basic reason why industry will remain in this province and why new industries will consider locating here in the future. Knowing that the province has an indigenous capability which is being developed will be a determining factor in many decisions. A healthy economy which can supply the number of jobs needed by Ontario residents can only exist in an economy that has adequate electrical power.[13]

The Ministry of the Treasury and Economics stated:

> It has long been a policy of successive Ontario governments and Ontario Hydro to provide power at the lowest possible cost with a price structure which is relatively uniform across the province. It has not been past policy to attempt to influence the location decisions of businesses by means of the rate structure. The allocation of costs among users is, therefore, intended to be neutral in its economic impact, and to generally maintain a competitive cost structure for our industries.[14]

More recently, in an appearance before the Select Committee on Hydro Affairs, R.P. Hill and R.J. Mifflin of the Ministry of Industry and Tourism downplayed the proposition that low-cost electricity is a major factor in attracting industry to the province. Mr. Hill asserted that only if Ontario's industrial electricity rates were to move out of line with those of other jurisdictions would the price of electricity become a major cost consideration to industry.[15] "In a very, very few situations will either the price or the availability of energy in general and electricity in particular be critical."[16]

His executive director, Mr. Mifflin, referring to the manufacturing industry's reaction to the rising cost of electricity, said: "I am not saying they are indifferent to it, but compared to the cost of labour, or the cost of materials or the cost of money, it is almost ho-hum, as indicated by the data."[17] Later, he concluded: "Low cost electricity, at least as far as the data indicates, has not been a major causal factor in attracting industry to settle in Ontario compared to, say, tariffs, natural resources, or proximity to markets."[18]

Ontario Hydro included an analysis of electricity's role in attracting industry to the province in Volume XB of the "Electricity Costing and Pricing Study" submitted to the Ontario Energy Board in 1976. This study concluded that attraction of new industry to Ontario and expansion of existing manufacturing

operations in the province will not be seriously affected by higher electricity prices in the future because of the greater importance industry attaches to access to markets in central Canada and the U.S.

> Overall in view of the minimal effect they have imposed on electricity-intensive industries, rate increases are not expected to exert any great impact on industries which use far less power, or on the Ontario economy as a whole. More probably, industry will adapt itself to less energy-intensive operations. In this regard, industries producing energy-conserving and antipollution equipment, and also such industries as uranium mining, are likely to locate in Ontario to supply the provincial manufacturing sector and the whole of Canada.[19]

In a study prepared for the Ontario Energy Board in 1978, Ontario Hydro cited the finding of the Urban Research Group (Canada) in 1970 that "labour cost, supply and quantity, the proximity to finished product markets, and the cost of land and raw materials are more important factors in the choice of location for an industrial plant than the cost of electricity".[20]

The Ontario Hydro report drew on the Urban Research Group analysis of investment trends in manufacturing plant and equipment in the province to show that "it is evident the cost of labour is likely to be of greater importance than the other factors mentioned above for most locational investment decisions".[21]

This section has attempted to present a range of perspectives on the role electricity supply is expected to play in the industrial development of the province. While a reliable and competitive electricity system is a precondition for a healthy industrial economy, most recent analyses suggest that the sheer availability of electricity will not serve as an engine to drive industrial development without favourable performance from a wide range of more important locational factors.

The Role of Electricity in the Development of Quebec and Manitoba

Quebec. The Quebec government has given a high priority to the integration of energy policy into the province's industrial strategy:

> Among the numerous businesses, associations and public authorities which are involved, only the government is in a position to be aware of all the facts and all action determining the part energy will play with respect to the Quebec community and the environment. It is the government's job to establish a strategy in which the various roles are respected and strengthened, but kept within economically sound and consistent bounds. Governments that try to avoid choosing a strategy are in fact opting for one, which may be the worst of all.[22]

In pursuing its industrial development strategy, the Quebec government has attempted to attract electricity-intensive and other manufacturing industries to the province by offering them special contracts that undercut the industrial electricity rates in other jurisdictions.

> The government wants to give itself an additional operating margin for industrial and employment development in Quebec. Combined with a systematic and determined industrial promotion effort, this margin should favour the setting up of industrial projects having maximum indirect economic benefits and liable to strengthen the manufacturing sector (secondary industry).[23]

Projected electricity price increases over the next three years favour primary electricity-intensive industries and small businesses – the main components of the government's economic development programme. Quebec could be in a strong position to compete with Ontario for new investment in electricity-intensive industries, despite the political uncertainty surrounding the province.

The present industrial electricity rate differential between Quebec and Ontario is about 0.3 cents per kilowatt hour for use of 1,000 kW. For larger electricity users, the rate differential between Quebec and Ontario, British Columbia, and Manitoba increases (see Table 4.8). Only Quebec offers volume discounts for customers with over 5,000 kW demand. As well, Hydro-Québec has instituted a special rate for industrial heating processes that encourages firms to substitute electricity for other fossil-fuel heat sources as part of Quebec's plan to become more self-sufficient in energy. In September 1979, the Quebec government announced that henceforth a committee of government and Hydro-Québec officials would set rates for prospective industrial customers with demand in excess of 5,000 kW, based on the investment in the province and the degree of upgrading of raw materials they propose.[24]

Table 4.8 Survey of Comparative Electricity Costs — Industrial Use — Large Users (rates effective March 1, 1979) (high voltage)

Municipalities	$/kW/month (excluding sales tax)[a]					
	5,000 kW		50,000 kW		100,000 kW	
	65%	85%	65%	85%	65%	85%
Canada						
Hydro-Québec	8.00	9.20	7.20	8.14	6.93	6.87
St. John's	12.34	15.19	N.A.	N.A.	N.A.	N.A.
Charlottetown	24.40	30.59	N.A.	N.A.	N.A.	N.A.
Halifax	14.97	18.23	N.A.	N.A.	N.A.	N.A.
Moncton	13.91	16.83	12.53	15.10	12.53	15.10
Toronto	10.46	12.42	10.46	12.42	10.46	12.42
Winnipeg	10.02	11.63	10.02	11.63	9.19	10.80
Regina	11.99	14.29	N.A.	N.A.	N.A.	N.A.
Edmonton	8.11	10.06	7.86	9.81	N.A.	N.A.
Vancouver	7.36	8.23	7.36	8.23	7.36	8.23
United States						
Houston	13.61	16.68	13.44	16.42	13.31	16.30
Boston						
New York[b]	30.84	36.98	28.43	34.58	30.19	36.33
Philadelphia						
Detroit	16.15	18.94	15.43	18.15	14.53	17.16
Chicago	13.97	17.10	13.12	16.07	12.78	15.73
Portland	8.54	10.56	8.37	10.24	8.10	9.98
San Francisco	14.32	17.76	14.22	17.66	14.11	17.55
Chattanooga	13.40	16.32	13.08	15.86	12.86	15.65
Seattle City Light[c]	3.19	3.71	2.30	2.85	2.30	2.85
Bonneville Power Adm., Portland	1.92	2.15	1.92	2.15	1.92	2.15

Notes:
a) Monthly average figures are shown when seasonal billing is applicable.
b) Rates effective April 24, 1979.
c) Rates effective April 29, 1979.
Source: Survey of Comparative Electric Costs, Hydro-Québec, Rate Division.

Quebec has projected that its policy of using low electricity prices to foster electricity-intensive economic development will raise electricity's share of total industrial energy consumption from 36 per cent currently to 50 per cent by 1990. Ontario's increasing dependence on nuclear-generated electricity puts this province at a competitive disadvantage *vis-à-vis* Quebec, whose hydraulic generating system has lower running costs, provides a more reliable supply of electricity, and does not face the same degree of public opposition.

However, Ontario continues to enjoy the advantages of proximity to markets for finished goods and processed raw materials, a larger skilled labour force, and political stability, which are frequently more important considerations in industrial location decisions than the price of electricity.

A study done by the Ministry of Industry and Commerce in Quebec in 1975 found that in only two electricity-intensive industries — smelting and refining (including non-ferrous metals) and pulp and paper — did Quebec have a larger share of total Canadian value-added in that industry than Ontario (see Table 4.9).

Table 4.9 Electricity-Intensive Industries and Their Importance in Manufacturing Activity – Quebec, Ontario, and Canada, 1971

SIC Code	Industry	Intensity of electricity consumption percentage			Share of consumption percentage			Share of value added percentage			Share of Canadian total percentage	
		Que.	Ont.	Cda.	Que.	Ont.	Cda.	Que.	Ont.	Cda.	Que.	Ont.
357	Abrasives	20.7	9.2	11.1	1.2	2.8	1.2	0.1	0.2	0.1	13.1	86.9
295	Smelting and refining	15.0	4.6	11.3	43.4	5.9	25.8	4.6	1.3	2.5	51.3	27.7
378	Industrial chemicals	5.3	4.2	6.4	4.6	14.5	12.1	1.0	2.5	2.0	14.2	65.3
352	Cement	5.2	4.7	4.5	0.9	1.7	1.1	0.5	0.4	0.6	23.3	36.7
271	Pulp and paper	5.0	5.3	5.0	30.3	20.8	27.1	7.6	2.9	5.9	36.4	26.0
291	Iron and steel	3.0	1.7	1.2	3.7	13.6	5.8	1.1	6.4	4.0	7.5	85.0
373	Plastics and synthetic resins	2.6	1.0	1.8	1.3	0.7	0.8	0.6	0.4	0.4	37.2	45.6
351	Clay products	2.6	2.2	2.2	0.1	0.2	0.1	0.1	0.2	0.2	13.4	57.8
358	Lime	2.6	2.5	2.4	0.1	0.1	0.1	0.1	0.1	0.1	22.8	55.3
309	Metal stamping and pressing	1.7	1.2	1.3	0.1	0.2	0.1	0.2	0.3	0.2	20.5	69.8
	Total manufacturing	1.6	0.8	1.4	100.0	100.0	100.0	100.0	100.0	100.0	27.9	53.4

Source: Statistics Canada.

> If the abundance of inexpensive hydro-electric power in Quebec has served to attract certain indus-
> tries, Quebec has not profited fully from this advantage – at least as much as one would have expected
> – since, with the exception of two industries, it is Ontario that has taken the lead in all industrial
> activities which are electricity-intensive.[25]

According to André Raynauld, analyst with the Quebec Ministry of Industry and Commerce, "the rate of structural transformation (la mesure du transfert de production entre les industries) in the Quebec economy and the growth in production is tied among other factors, first, to the demand elasticities for electricity in provincial enterprises and, second, to technological innovations".[26]

Raynauld has found that growth patterns of industries in Quebec and Ontario reflect the historical advantages that each province has in particular types of production: "Quebec will continue, as it has for a long time, to have advantages in light industry, based principally on consumption goods, whereas Ontario will continue to have more heavy industry, especially products of the iron and steel industry".[27]

Quebec is hoping that by integrating its industrial strategy with its energy policy it will accelerate industrial development in an age that gives increased prominence to its traditional asset, hydroelectricity. In the process, it will offer more serious competition to Ontario for extremely electricity-intensive industries than it has in the past.

Manitoba. The limitations in using availability of low-cost electricity as a means of attracting industry to a jurisdiction are evident in the case of Manitoba, which has not succeeded in establishing a broadly-based manufacturing sector despite the secure supply of inexpensive electricity offered by Manitoba Hydro. Mining, processing, and specialized manufacturing industries in Manitoba have been attracted by hydroelectric power at rates only slightly higher than Quebec's. Expansion of Inco and Sherritt Gordon nickel, copper, and zinc mines at Thompson and Ruttan Lake, for example, has been expedited by special contracts negotiated with Manitoba Hydro that gave these companies access to abundant supplies of electricity at reduced industrial rates, in return for investment on their part in dam and transmission-line construction.

The combined electricity development and mining industry activity did stimulate the economy of northern Manitoba. Many residents were employed on construction projects, in the mines, and in service industries in nearby communities. However, the slow-down in mining activities during the last two years and a substantial decline in demand for electricity have created economic problems in the northern region. Manitoba Hydro has now suspended work on its $1.2 billion Limestone power plant on the Nelson River because the province's electricity demand is increasing at less than 3 per cent a year, compared with the historical 7 per cent. Because a manufacturing industry was not developing in Manitoba of its own accord, the federal Department of Regional Economic Expansion (DREE) stepped in in 1969. Since the inception of the industrial incentives programme in Manitoba, almost $200 million in grants has been given to firms for new capital investment in manufacturing and processing activities. J.P. Francis, an assistant deputy minister with DREE, described its approach at a conference in 1972:

> The reasons for limiting the grant to manufacturing and processing are fairly obvious. These are the
> types of activities whose location can be influenced and they are the kinds of activities which, if

expanding, will give the greatest thrust to the whole regional economy. The first step is to select a number of areas where economic expansion is already taking place, mainly because of the resources and electricity availability in the region, and to develop a programme which helps the people of these areas take advantage of the new opportunities coming forward.[28]

A major project undertaken by DREE was the establishment of Le Pas as a light manufacturing and processing centre to take advantage of an abundant supply of inexpensive electricity and raw materials from Flin Flon and Lynn Lake in Manitoba's mid-northern region. Early in 1979, DREE agreed to give $82.5 million to the Manitoba government's "Enterprise Manitoba" programme during the next five years to expand the mineral processing, light machinery, transportation equipment, aerospace, and electronics industries in that province. DREE's ongoing presence in Manitoba highlights the importance of factors other than the reliability and price of electricity in drawing industry to a region.

Competition for Electricity-Intensive Industries in Canada

This section surveys some of the factors affecting the industrial location of the most electricity-intensive industries in Canada. The industries discussed are: smelting and refining, pulp and paper, abrasives, and cement. Data summarizing employment, value-added, and electricity costs for these industries in Ontario and Quebec is presented in Table 4.10.

Table 4.10 Comparative Employment, Value-Added, and Electricity Costs in Selected Electricity-Intensive Industries

	Employees		Value-added ($000)		Electricity costs ($000)	Electricity costs as a percentage of value-added
	1965	1975	1965	1975	1975	1975
Smelting and refining						
Ontario	11,260	9,830	84,940	182,146	14,577	8.0
Quebec	12,352	16,164	216,957	424,635	29,618	7.0
Pulp and paper mills						
Ontario	21,038	20,912	285,844	503,784	32,483	6.4
Quebec	27,455	31,946	381,112	817,383	58,405	7.1
British Columbia	10,827	17,826	227,826	727,015	21,228	2.9
Cement						
Ontario	1,163	1,310	36,327	73,971	5,475	7.4
Quebec	1,346	1,725	32,340	61,960	4,418	7.1

Sources: Statistics Canada: "Manufacturing Industries of Canada, National and Provincial Areas". Catalogue No. 31-203, 1975. "Manufacturing Industries of Canada: Ontario and Quebec". Catalogue Nos. 31-206, 31-205, 1965. "Consumption of Purchased Fuel and Electricity by Manufacturing, Mining, and Electric Power Companies". Catalogue No. 57-208, 1975.

These industries are not drawn by the business climate of a region so much as by the quality of its natural resources and/or the price of its electric power. In general, as the economically exploitable resource base of the mineral and wood products industries approaches exhaustion, local profit margins decline and capital investment is focused where the economics of extraction are more favourable. Electricity rates and tax policies will have some impact on profit margins but ultimately probably cannot compensate for the more fundamental resources factor. Abrasives and cement are more mobile, given a competitive electricity source.

Smelting and Refining. The major electricity-intensive industry not located in Ontario is aluminum smelting, which is concentrated in Quebec and British Columbia. Without that industry, value-added in smelting and refining in Quebec would be roughly the same as in Ontario, rather than twice the amount (see Table 4.10). Nearly half of the electricity consumed by the smelting and refining industry in Quebec takes place in the Alcan Aluminum Company smelters at Arvida. This share will rise further when Alcan's new smelter at Ville de la Baie comes on stream in the early 1980s. Alcan chose to locate in Quebec mainly because of the opportunity to develop accessible hydroelectric power sites. At the time, the St. Lawrence Seaway had not been completed, so the passage of ore carriers to Ontario would have been restricted.

The Ontario government has used special tax legislation to encourage further growth of mineral processing in the province. However, this will probably not reverse the tendency of large mining companies to shift some production to Quebec, to other Canadian provinces, and overseas, where richer ore bodies and cheaper labour may be found. Officials of Ontario-based mining companies maintain that they are committed by heavy capital investment in mines and processing facilities to remain in the

province, and that the political and economic stability and secure supplies of electricity and other energy sources here provide a measure of security not found in many of the other areas where they have permanent establishments.

Representatives of the mining, smelting, and refining industries have participated actively in lobbying by the Association of Major Power Consumers (AMPCO) for low industrial electricity rates to encourage electricity-intensive resource extraction and processing operations in Ontario. They argue that electricity prices have become a more important variable in production costs, and that rate increases should be limited to keep current and prospective operations in the province competitive with those in other jurisdictions.

Pulp and Paper. In recent years, Ontario has dropped behind both Quebec and British Columbia in its share of total Canadian pulp and paper production. Relatively old and inefficient mills, combined with less productive timber lands here, and higher electricity costs, have contributed to the erosion of the competitiveness of the industry in Ontario. Consequently, some firms in the province have begun to modernize existing plant and equipment and to rely more on self-generation of power from the recycling of solid wastes and biomass conversion.

The province would like to encourage construction of modern facilities such as thermo-mechanical pulping (TMP) plants, which increase pulping capacity, reduce costs by efficient use of wood, reduce pollution, and produce pulp that is stronger and cleaner than the stone ground wood currently being used.[29] Conversion to the TMP process would also increase the amount of electricity consumed in the production of pulp by about 40 per cent. This is less, however, than the increase of from 50 to 100 per cent that is required when pollution-abatement equipment is installed in existing pulp and paper mills.[30]

The Ontario government proposed in January 1979 that up to $100 million in provincial grants be allocated to the pulp and paper industry to cover a maximum of one-third of its capital expenditures on modernization and pollution control.[31] At about the same time, Quebec initiated a long-term assistance programme to revitalize its pulp and paper industry.

Apart from Quebec and British Columbia, the province also faces competition from firms operating in the southeastern United States, where faster-maturing wood crops, modern plants, low-cost labour, and tax incentives from state governments provide favourable conditions for the production of pulp and paper.

Abrasives and Cement. The abrasives industry is particularly sensitive to changes in electricity prices, since electricity expenditures are equivalent to 17.0 per cent of value-added in the manufacture of fused alumina, abrasive wheels and segments, and other synthetic abrasive products. Ranked by electricity expenditures as a percentage of shipments, the cement industry is the third most electricity-intensive industry in the province. Vulnerability to electricity price increases is not a new problem for abrasives and cement manufacturers. In 1966 when non-uniform tariffs were terminated, these industries lost their favourable regional rates. They are now charged on the same basis as other industrial users.

Ontario Hydro's "Electricity Costing and Pricing Study" (ECAPS) noted that the electricity intensiveness of the abrasives industry has been responsible for its concentration in the Niagara Peninsula, where, historically, the cheapest hydroelectric power was available. The study observed that this clustering of abrasives manufacturing plants could create serious problems for the industry and for the economy in the Niagara area should electricity prices increase substantially.

Eight batch furnaces used to manufacture synthetic abrasives products at Canadian Carborundum's Niagara Falls operations were closed in 1976, causing 50 employees to be laid off. Another 150 workers could lose their jobs if the company decides to relocate its tilt furnaces to existing Quebec or New York facilities where cheaper electricity is available under long-term contracts.

The ECAPS also maintained that the Ontario cement industry could face the same dilemma in the future should electricity rates continue to rise substantially above present levels. The index of electricity consumption per employee is higher in the manufacture of cement than in abrasives. However, since employment in each industry represents only 0.2 per cent of the total in all manufacturing, the impact of a decline in production in either the abrasives or the cement industry would fall more heavily on the regional than on the provincial economy (see Table 4.6).

The ECAPS case study of the cement industry concluded: "... if electricity costs in Ontario do rise

significantly above those in Quebec, it many be profitable for future expansion by the Canadian cement industry to shift to Quebec. If this were to occur, many jobs, both directly and indirectly tied to the cement industry, would be lost from Ontario."[32]

Conclusions

Historically, many electricity-intensive industries, predominantly raw materials processing firms, came to Ontario to take advantage of the ready access to markets in central Canada and the United States, abundant raw materials, a growing skilled labour force, favourable tax and tariff structures and low-cost electricity. Government analysts now acknowledge that electricity prices are of less importance in attracting industry to the province. Furthermore, in the 1970s, the contribution of primary industry to provincial GDP has fallen from 4.3 per cent in 1970 to 2.4 per cent in 1978. Competition from other raw material processors in Canada and abroad, combined with such factors as a decline in the forest resource base for the pulp and paper industry, threatens this traditional driving force behind the Ontario economy. As a result, Ontario will have to place more emphasis in the future on the competitiveness of its work force, technology, and tax incentives.

Ontario's electricity costs will continue to be higher than those in Quebec, in the long run because of the economics of nuclear versus hydraulic generation, and in the short run because Ontario's surplus generating capacity is mostly oil-fired. Reliability of service is extremely high in Quebec, so that security of supply will not be a relevant criterion. These factors, combined with Quebec's intention to provide special power contracts to stimulate industrial expansion, indicate that the most electricity-intensive firms may prefer to locate in Quebec, particularly when the political situation stabilizes.

There is little likelihood of major out-migration of electricity-intensive industries from Ontario to other jurisdictions, even if electricity prices here rise somewhat further relative to those of Quebec, Manitoba, British Columbia, and the cheapest American utilities. Cost advantages in these jurisdictions are not likely to outweigh the costs of moving combined with Ontario's advantageous locational factors, particularly proximity to markets.

Should industries such as abrasives and cement decide to relocate in other jurisdictions, the loss of jobs in Ontario would be relatively small, since each industry accounts for only 0.2 per cent of the total employment in manufacturing in the province. The impact of relocation by such electricity-intensive industries would, of course, be more serious at the regional level. Careful advance planning by the industries involved, together with government, would be required to ensure that the hardship to the workers is minimized.

Employment in the electricity-intensive subsector has held relatively constant over the last 10 to 15 years. This cannot be completely explained by an increase in the capital-to-labour ratio. The output growth of this industry group has been below the manufacturing average.

In summary, only for a very few highly electricity-intensive industries would the price of electricity be a significant factor in choosing the location of a production facility. Reliable service would be a prerequisite for a wider range of companies, but this is a characteristic Ontario will continue to share with numerous other jurisdictions in Canada and the U.S.

An adequate and relatively inexpensive supply of electricity is certainly one of the preconditions for establishing a balanced industrial development programme, but it will do little to foster new development by itself. Strong integrated sectorial strategies will be required to preserve the health of Ontario's manufacturing industry.

Prospects for the Export of Electricity

Exports of Electricity in the 1980s

With the exception of the recent contract with General Public Utilities of Pennsylvania, all the secondary sales of electricity by Ontario Hydro in the last few years have been exports of power to New York and Michigan. Since 1975, Hydro has been licensed by the National Energy Board (NEB) for interruptible power exports only, so that sales have been negotiated on an almost day-to-day basis. Firm contracts would require approval of a special application to the NEB.[33] (Note 33 provides a brief review of the terminology and pricing of the major types of electricity transactions and a summary of the considerations made by the NEB in approving export contracts.)

Ontario Hydro makes, basically, two types of electricity transactions: capacity sales and economy sales. Capacity sales occur when the buyer has an emergency and effectively no alternative generating capacity. A contract may be for one day or short-term (usually about a week). A premium price is negotiated in each case, and it is at least Hydro's cost plus 10 per cent. The average revenue from capacity sales in 1977 was $27.80 per megawatt hour. The average bulk power cost for Ontario customers was about $18.50 per megawatt hour.

Economy sales result when the fuel costs of the buyer's available generating capacity are higher than the running costs of Ontario Hydro's spare capacity. In the most common transaction, production from coal-fired Hydro capacity is sold to replace oil-fired generation in the U.S. The price of the sale is the average of the replacement cost to Hydro of the fuel burned and the value in the market of the electricity (the marginal cost to the buyer of using his own capacity). As it is not Hydro's present policy to install capacity for the purpose of export sales, capital costs are not included in estimating Hydro's costs. When reserve capacity is available it is viewed as surplus, and, accordingly, Hydro sets its cost to recover variable (mostly fuel) costs only. The average sale price of economy power in 1977 was $22.25 per megawatt hour. Cost to Ontario Hydro in that year was estimated to have been about $14 per megawatt hour.

One way to get a sense of the prospects for capacity sales is by examining the reserve margins of the purchasing utilities in the light of the make-up of their generation system and their load forecast. Low reserves are, however, far from a foolproof guide to possible capacity sales as many outages are quite unforeseen and may necessitate months of repair work. Economy sales are price-determined so that the volume of sales made by Ontario Hydro depends on the competitiveness of its source of spare generation, compared with the cost of fuel for marginal generation in the buyer's system or the cost of the alternative sources he has open to him.

Nuclear generation is unlikely to be "on the margin" off peak (i.e., increments to off-peak demand will continue to be met by coal-fired stations) until the late 1980s, so that all exported power in the 1980s will be effectively from fossil-fuelled stations. The next section explores the options for the 1990s, when exports of nuclear power may be possible. To avoid economic losses, sales of fossil-fuelled electricity must be priced so that, at a minimum, they recover the running costs of the plant operating at the margin at the time of the sale and as much of its capital cost as the market will bear. Units fired with oil or western Canadian coal would therefore have difficulty competing for economy sales.

There appears to be a reluctance on the part of nearby U.S. utilities to enter into firm contracts for power. It may be better for them to view Ontario's excess capacity as part of their reserve margin than to commit themselves to power purchases or to delay or defer local construction. The major benefit to both parties of improved interconnections may be the increased system reliability to be derived from sharing reserve capacity. Ontario Hydro expects firm contracts to be less than 500 MW during the 1980s (Figure 4.1). Some of the factors discouraging firm contracts will become apparent in the discussion of the outlook for interruptible sales.

In the case of sales to New York, Ontario must compete with Hydro-Québec. Quebec has several advantages, and these will be analysed later in this chapter. Michigan's closest U.S. neighbours are American Electric Power and Toledo Edison Company to the south in the East-Central Area Reliability Grid (ECAR). These companies have numerous, efficient, coal-fired stations located at mine-heads that produce cheap electricity in comparison with Ontario Hydro's coal-fired generation. The substantial sales to Michigan in the last two years reflect the difficulties experienced by both Michigan utilities and their neighbouring U.S. utilities as a result of the coal-miner's strike in 1978 and the severe winters.

Secondary Sales in 1976-9. Exports of electricity grew from 1.8 million MW·h in 1971 to 6.0 million MW·h in 1974 and then dropped to 2.0 million MW·h in the recession year, 1975. Sales of 4.1 million MW·h in 1976 were still low, just above the 1972 level, and contributed to Ontario Hydro's $46 million revenue shortfall that year. In 1977, secondary sales rebounded to $206 million, earned on sales of 8.4 million MW·h. In 1978, primarily due to the coal-miner's strike in the U.S., the volume of export sales reached 10.4 million MW·h valued at $284 million. Exports in 1979 have been boosted by the contract with General Public Utilities that replaces part of the power lost because of the accident at the Three Mile Island nuclear plant. Sales may reach 12.0 million MW·h, but this could be the peak for some time to come. Ontario Hydro's "Long Range Financial Projection, 1979-1999" expects secondary sales to range between 7.0 and 11.0 million MW·h during the period 1979-84 and to be at about the 6.0 million MW·h level thereafter.[34] Table 4.11 provides detailed statistics of secondary sales for 1976-8.

Michigan was Ontario Hydro's best customer, buying about 70 per cent of the total electric energy exported in 1976-7 and 84 per cent in 1978. Economy sales made up about 60 per cent of total sales. Table 4.11 shows that, in 1977 and 1978, 90 per cent of Hydro business with New York was economy sales and that these sales fetched appreciably lower prices than those made to Michigan. The average revenue per MW·h earned by Hydro for exported power was $27.42 in 1978, compared with Ontario gross bulk power costs of $22.12.

Table 4.11 Ontario Hydro Secondary Sales in 1976-8

	Electricity (millions of MW·h)			Gross revenue ($ million)			$/MW·h		
	Capacity	Economy	Total	Capacity	Economy	Total	Capacity	Economy	Total
Michigan									
1976	1.0 (25%)ᵃ	1.8 (44%)	2.8 (69%)	25.1	44.6	69.7	25.10	24.85	24.89
1977	2.9 (35%)	3.2 (38%)	6.1 (73%)	81.8	77.2	159.0	28.20	23.99	26.07
1978	3.8 (37%)	4.9 (47%)	8.7 (84%)	123.2	128.0	251.2	31.04	26.11	28.76
New York									
1976	0.65 (5.5%)	0.65 (5.5%)	1.3 (31%)	16.4	10.7	27.1	25.23	16.98	20.85
1977	0.3 (2.0%)	2.0 (25%)	2.3 (27%)	7.4	39.4	46.8	24.67	19.43	20.35
1978	0.16 (2%)	1.5 (14%)	1.6 (16%)	5.1	27.5	32.6	31.71	18.66	19.94
Total									
1976	1.6 (41%)	2.5 (59%)	4.1 (100%)	42	55	97	25.45	22.85	23.79
1977	3.2 (37%)	5.2 (63%)	8.4 (100%)	89	117	206	27.81	22.25	24.53
1978	4.0 (39%)	6.4 (61%)	10.4 (100%)	128	156	284	32.48	24.37	27.42

Note a) Percentage of the year's total secondary sales.
Source: Ontario Hydro, Interconnections Department, February 1979.

Profits on secondary sales are calculated as the difference between the gross revenues from exports and the replacement cost of the fuel plus a small allowance for additional maintenance. On this basis, 1978 profits may be estimated at about $100-120 million.

Since the quantity of power and the generation source available for interruptible exports is negotiated on an hourly basis, secondary sales do not lend themselves readily to long-term projections. Ontario Hydro's forecasts of annual revenue from electricity exports are highly judgemental, taking into account, among other factors, Hydro's reserve margin, relative costs, and the expected need of Michigan and New York for power from Ontario. Hydro's forecast in the spring of 1976[35] for 1977 sales was 4 million MW·h. This was revised to 5 million MW·h early in 1977 but still considerably underestimated the final total (8.4 million MW·h). Hydro expected sales in 1978 to roughly equal 1977's performance on the grounds that the conditions that had created the sizable demand for capacity and economy power in Michigan were likely to persist for another year or two. The coal-miners' strike prompted a 25 per cent increase in 1978. In the spring of 1978, the forecast made for secondary sales in 1979 was 8 million MW·h. Events surrounding the Three Mile Island nuclear accident contributed to a revised forecast in mid 1979 of 12 million MW·h.

Current Supply Conditions in Michigan and New York. With the exception of the Power Authority of the State of New York, the utilities in the regions bordering on Ontario are owned privately although still regulated publicly. They tend to be cautious in committing themselves to capacity expansion and are subject to more severe capital availability problems than publicly-owned systems. For instance, Detroit Edison, the largest utility in Michigan, halted its construction programme in 1974 because it was unable to raise sufficient funds in the capital market, either through the issuance of debt or additional share capital. In those years, load growth was essentially flat, though it is picking up now. During the period in which capacity expansion catches up, Detroit Edison will need to purchase power from interconnected utilities. Ontario Hydro is regarded as a reliable emergency cushion by both

Michigan and New York. As noted above, it is probably more in their interest to consider our excess capacity as part of their reserve margin than to arrange firm power sales.

Demand for electricity in New York only grew by 4 per cent between 1973 and 1978 due to stagnant industrial development in downstate New York. At present, there is a surplus of capacity in the New York Power Pool (NYPP), with a summer reserve margin of 40 per cent and a winter margin of 55 per cent. However, as about half the total capacity is oil-fired, there is an ongoing market for economy sales.

Michigan utilities do not co-ordinate their planning activities to the extent that the New York utilities do. However, when purchases of electricity are made, the transaction is administered by the Michigan Electric Power Co-ordinating Grid. The Michigan system is dominated by two utilities: Detroit Edison (1977 capacity, 8,584 MW) serving the main urban centres and Consumers Power (1977 capacity, 6,230 MW) supplying the rural districts. The other utilities together produce about 10 per cent of Michigan's electric energy. The Consumer's Power Company will not likely be either a significant purchaser of capacity or, because its summer and winter peaks are almost identical, a suitable candidate for diversity power sales.

The Detroit Edison system currently generates its electricity from coal and oil. About one-third of its capacity is accounted for by the Monroe coal-fired station (3,200 MW), which had unusual equipment failures in the spring of 1977. The cold winter of 1976-7 stopped shipments of coal to the station, and coal inventories froze in the pile and were inaccessible. In 1977-8, coal supplies were interrupted by the miners' strike and again inventories were of little help. With such difficulty in utilizing its coal-fired stations, Detroit Edison has been obliged to turn to its 2,000 MW of oil-fired capacity. It will be economic for the utility to substitute coal-fired capacity from Ontario (and American utilities to the south) for this expensive source of electricity until a 1,100 MW nuclear station that is expected to be in service in 1981 is complete.

Hydro Capability for Secondary Sales in the 1980s. Even with the mothballing of Wesleyville and the delay of Bruce B and Darlington, the expansion programme chosen to meet Ontario Hydro's 1979 load forecast will result in about 3,500 MW of excess capacity in the East System to the mid 1980s, falling off to about zero by 1990 (see Figure 4.1). Excess capacity is measured as the difference between rated system capability and 25 per cent above firm peak load.

Sale of Ontario Hydro's generation surplus is also constrained by transmission capability both in Ontario and in the U.S. Ontario Hydro's submission to the RCEPP in November 1978, dealing with the total system, put firm sale capability in the range of 500-1,500 MW from 1983 on, but actually negative until 1983. As Ontario load grows after 1983, transfer capability to other utilities will decline unless the provincial transmission network is reinforced. Hydro's 1978 "Review of the System Expansion Plan" indicated that wheeling capability (i.e., the ability to transfer power from one utility to another not directly interconnected over the transmission lines of the adjacent utilities) through New York and Michigan to U.S. power pools interconnected with these states was limited to 500 MW each, so that these two states will remain Ontario's major export market for the next decade. Further discussion of power transfer capability may be found in Volume 2 of this Report.

Prospects for Secondary Sales in the 1980s. To get a view of the prospects for the 1980s one is obliged to judge the reasonableness of the load forecasts made by the utilities to the south of us and then assess the likelihood that they will be able to complete their capacity expansion programmes as required. One can only speculate about inabilities to finance, shortages of fuel (coal and oil particularly), environmental delays, equipment malfunctions, and so on. It is apparent that the private utilities in the northern U.S. are forecasting lower growth rates than Ontario Hydro, perhaps reflecting the relocation of industries from the U.S. Northeast to the sun-belt states. Demand forecasts from different regions are not comparable, but, if the utilities in New York and Michigan are being too cautious, several years of strong growth could create an opportunity for Ontario Hydro. If they are planning well, sales will likely return to the lower levels in the 1979 long-range forecast by Hydro, noted above.

The 1978 Long Range Plan of the member electric systems of the NYPP predicts that peak demand in New York state will grow at an average annual rate of 2.9 per cent during the early 1980s, declining to 2.6 per cent by the late 1990s.[36] In 1976, the National Economic Research Associates, consultants to all the member utilities, forecast summer peak demand in the period 1974-86 increasing by 3.5 per cent to 4.8 per cent. They have now reduced their forecast to centre around 3.5 per cent.

If the NYPP forecast is correct, the reserve margin in the New York system will fall below the target 23

per cent threshold only in 1988.[37] This reserve margin is expected to be over 30 per cent until 1981 and about 25 per cent in the mid 1980s.

Incorporated in the NYPP's plans for the 1980s are summer purchases of 800 MW of capacity from Quebec. Unless New York's load forecast is seriously low, Ontario's potential for capacity sales to New York appears limited. As noted above, it is difficult to estimate economy sales made on a daily basis. However, recognizing the large share of oil-fired capacity in the NYPP, and, assuming increasing availability of U.S. coal to Ontario Hydro as at present contracted, the prospects for economy sales are promising. President Carter's July 1979 energy speeches may motivate American utilities to reduce their use of oil as a fuel for electricity generation faster than they otherwise might have done. Initially, during the period when conversions of oil-fired boilers to coal are taking place, Ontario may benefit from additional export sales, but in the longer term the market for economy sales will probably decline. Ontario will be obliged, however, to compete with Hydro-Québec for economy sales.

Hydro-Québec is Ontario's major competition for economy and capacity sales to the NYPP. Its long-term export contract, with its associated high-voltage interconnection, will make Quebec the top-priority seller to New York. Also, the low and stable marginal costs of Quebec's primarily hydraulic generating system will ensure that whenever the NYPP is in the market on a day-to-day basis, Hydro-Québec is likely to have first refusal on the sale.

The capability of Hydro-Québec as of January 1978 is rated at 17,300 MW, of which 94 per cent is hydraulic. This includes the firm purchase of Churchill Falls power from Newfoundland under a long-term contract, the price clauses of which are currently being contested in the courts. In 1985, after the first four major projects in the James Bay Development are producing electricity, the system will still be 90 per cent hydraulic.

The Quebec government report "An Energy Policy for Quebec" projects growth in consumption of 6.4 per cent per annum averaged to 1990.[38] The associated capacity expansion programme is designed to meet the winter peak including generating reserves. However, in part because of large electric space-heating loads, Quebec's winter peak is about 50 per cent above the average summer day's peak, leaving ample capacity for diversity sales (for a definition, see note 39) which would be limited only by trans-mission capability. Should Quebec's efforts to attract industry by offering preferential electricity sup-ply contracts fall short, Quebec will have further surplus capacity for sale either in Canada or the U.S. In July 1979, the Premier of Quebec announced that by 1982 Quebec would have an annual surplus of 9-12 million MW·h available for export.

Ontario's market for economy sales in New York will likely vary with Hydro-Québec's ability to satisfy the NYPP's needs. In the long term, Quebec's argument to the NEB that it can sustain its rated capacity output by manipulating its reservoir levels would justify at least two or three times the exports that are at present under contract. Ontario Hydro will likely find Michigan to be a more dependable export market than New York in the 1980s and, if need be, could import from Quebec.

Ontario does not face competition from hydroelectric systems for export sales to Michigan. The outlook for diversity sales to Michigan, and Detroit Edison in particular, is promising. Detroit Edison probably purchased the lion's share of the 8.7 million MW·h sold to Michigan in 1978, which was about 15 per cent of that state's total energy requirements. Its urban market has a large air-conditioning load in the summer — August demand is about 25 per cent above mid-winter peak.

The prospects for year-round sales to Michigan are less clear. Detroit Edison's summer peak load is forecast to grow at 3.2 per cent on average between 1978 and 1987. Peak capability will increase at a 3.3 per cent average annual rate over the same period, but the addition of large units to the system will not augment capability smoothly over time. Intermittently during the 1980s, Detroit Edison's economic load-meeting capability may be stretched, though reserve margins based on the 1978 load forecast will not drop below 23 per cent to 1987. Unless Detroit Edison has underforecast its load or experiences a severe setback to its expansion plan, Ontario's export sales will probably depend on unpredictable disruptions to coal supply. Ontario is also vulnerable to this threat.

Exports of Nuclear Power in the 1990s

Under the 1979 load forecast, it is likely that, after the last unit of Darlington comes into service in 1990, the Ontario Hydro system will approach a configuration in which nuclear and hydraulic supply all base loads and the reserve margin returns to 25 per cent. At this point, nuclear capacity would be close to the margin off peak on the winter peak day, and further penetration of the daily load curve by

nuclear units would be subject to operational constraints, unless the CANDU system develops improved load-tracking capability. Only after nuclear has achieved its target mix in the system will excess nuclear power be available for export. Prior to that, incremental export demand will be served by fossil stations.

If load growth turns out to be lower than predicted in the 1979 forecast, Ontario Hydro will reach its desired nuclear share earlier than 1990, though probably not much before the completion of Bruce B (and a second 500 kV transmission line out of Bruce). Should load growth drop unexpectedly, Hydro would turn to the export market to recover as much as possible of the capital cost of the station, in order to reduce the cost to Ontario customers of an overbuilt generating system.

Accelerating the nuclear programme has little potential to bring forward the capability to export base-load energy from CANDU units. It would involve returning committed stations to their original schedules and advancing the construction of uncommitted units. Given the long lead time for nuclear stations, very little, if any, surplus nuclear capacity could be created by such a policy before 1990. As the previous section indicated, the utilities closely interconnected to Ontario Hydro expect committed capacity expansion to keep pace with projected demand in the 1980s. Long construction lead times in the purchasing system limit the freedom of those utilities to commit themselves to purchases in the 1980s. Significant exports of nuclear-generated electricity are unlikely before the 1990s.

Exports of nuclear power might benefit the Ontario economy in several ways. They would earn considerable revenues for the province from an energy source that has a high Ontario content and so help to offset other energy imports. Less directly, an increase in the demand for power from CANDU reactors would help the nuclear supply industries to operate at a more viable level. Ontario Hydro's 1979 load forecast calls for the building of one 850 MW reactor per year to the year 1994. This may be close to a minimum-order threshold below which radical measures would need to be taken to preserve the option of an indigenous component industry. If load growth falls below the 1979 Hydro forecast rate of 4.5 per cent, exports of nuclear-generated electricity may serve only to sustain the current one-reactor-per-year order level.

The base-load operational characteristics of nuclear stations and their heavy front-end capital requirements suggest that firm export contracts should be negotiated well in advance of the availability of surplus nuclear power. Contracts could be for several years, if the plant is part of Ontario Hydro's ongoing expansion programme but enters service prior to need; or for the life of the plant, if built specially for export duty. A nuclear station dedicated to the export market could be owned either by Ontario Hydro or by a private consortium, although it would probably be constructed and operated under Hydro's supervision.[40]

U.S. utilities might commit themselves to purchasing a block of power for 30 years, beginning 10-12 years from now; however, it is more realistic to expect that firm export contracts of only a few years' duration could be arranged. From the perspective of the buyer, a take-or-pay contract for electricity from a station dedicated to that buyer is almost equivalent to the buyer purchasing the CANDU unit outright and undertaking to finance it. The advantages of essentially leasing the nuclear station would have to be great enough to overcome the resistance of the U.S. nuclear lobby (including the U.S. nuclear components industry, labour, and government at all levels), who would see such a transaction as the loss of jobs and indirect benefits from an already ailing American industry. The possibility of direct sales of CANDU units to the U.S. has been discounted for some time despite the low unit energy cost and outstanding performance record of those units. The construction of a reactor just north of the border for transmitting power to the south is not much different.

There are several factors that appear to counter the forces that have kept CANDU out of the U.S. How relevant they are is a subject of some debate. U.S. utilities are facing growing opposition to nuclear power, for environmental and social reasons. In some states, approval procedures are lengthening lead times to the point where the nuclear option is put seriously in doubt. Also, concern about acid rain may limit the use of coal-fired stations in some states. The substitute source of electricity could, perhaps, be nuclear power from Ontario. Under these conditions a surplus nuclear station for which all approvals had been obtained in Ontario would be extremely valuable. It is not clear, though, whether Ontario, whose reactors normally take about two years longer to build than American designs, would be able to put an as yet uncommitted reactor, dedicated for export service, into place any faster than a U.S. utility could complete one of its own.

A second issue is financing. Some private U.S. utilities have experienced capital availability problems,

or, because of their low credit rating, face prohibitive interest charges. If a station designated for export could be financed under the provincial guarantee, it would have a considerable cost advantage over a station built by a private U.S. utility. It is unlikely that a private consortium could lease a privately financed reactor to a utility with, say, a BBB bond rating, and finance the station with cheaper money than would be available to the utility itself. The risk of lending to a consortium may be perceived by capital markets as greater than the risk of lending to a utility directly. A large equity component, yielding little dividend for 10 years, would probably be required.

Conclusions

Given the long lead times experienced by all electric utilities, Ontario's potential customers in New York and Michigan are already proceeding with their expansion plans for the late 1980s. Ontario Hydro is in a position to augment the medium-term capacity of these utilities but is unlikely to be able to substitute its capacity for theirs. Secondary sales will be predominantly of coal-fired peaking capacity, replacing oil-fired thermal generation, particularly in the summer months.

The high sales to Michigan in 1977-8 of both capacity and economy power were caused by extreme events in the coal industry (which also crippled Michigan's least-cost alternative, American Electric Power), unusual equipment malfunctions, and a lagging expansion programme. These factors may very well moderate in the next year or two. In the medium term, Michigan could be vulnerable to any generic difficulties experienced by American electric utilities. One possibility, inadequate production by the U.S. coal industry, could, of course, strike heavily at Ontario Hydro as well.

The outlook for the New York Power Pool is for healthy reserve margins as long as their forecast is not excessively underpredicted and their nuclear programme is close to schedule. Nearly half of the capacity in New York is oil-fired, creating a large market for economy sales. Hydro-Québec appears to have an increasing edge in selling to New York because of stable, low-marginal costs and mounting surplus capacity.

Figure 4.1 illustrates Ontario Hydro's estimate of the excess generating capacity in the East System and its expectations for firm and interruptible sales.[41] The export prospects are consistent with the discussion in this section. The unexportable surplus is composed almost entirely of oil-fired capacity (Lennox, 2,200 MW) and would probably be in demand for export only in an emergency. The West System is interconnected with Manitoba, which has already tapped the export markets in the states south of it.

The American utilities with which Ontario Hydro has direct interconnections are projecting quite low load growth relative to the U.S. as a whole. The fastest-growing utilities in the U.S. are in the south, though it should be noted that load forecasts across the U.S. have fallen steadily over the last four years. The U.S. composite load forecast for 1977-83, made in 1974, was for 7.4 per cent annual growth. In 1978 it was down to 5.4 per cent. It is the even greater reduction in installed capacity forecasts that has provoked concern for the reliability of electricity supply in the U.S. in the mid 1980s (7.9 per cent growth forecast in 1974 versus 4.6 per cent in 1977). If the nuclear programme is seriously delayed, reserve margins will be unacceptably low throughout the U.S.

Ontario Hydro's potential to make secondary sales in the 1980s may be undermined in the years ahead, even with surplus capacity. There is unlikely to be spare hydraulic or nuclear power for export. As Alberta coal becomes an increasing proportion of Ontario Hydro's coal-pile, the replacement cost to Ontario Hydro of the coal burned for export could reduce the profitability of export sales substantially.

The outlook for significant export sales of nuclear power in the 1990s, with its attendant benefits for the Ontario economy, is at best uncertain. Because our neighbouring utilities in Canada have abundant hydraulic potential, Ontario has been obliged to direct its efforts at the U.S. market, which has resisted competition from CANDU reactors. The long lead time, from the decision to build to the commissioning of a nuclear station, increases the risk and the financing problems to the point where such a project may not be viable as a private venture designed to capitalize on a deterioration in northeastern U.S. electricity supply. Advancing the in-service dates of Ontario Hydro nuclear stations by several years in order to sustain activity levels in the nuclear industry would present considerably less financial risk.

Figure 4.1 Ontario Hydro East System — Excess Generation Capacity (Relative to 25% Reserve) and Potential Export Market

MW

1979 expansion plan

Expected total market for firm and non-firm power sales

Expected market for firm power sales

Year (winter of)

1979/80 80/81 81/82 82/83 83/84 84/85 85/86 86/87 87/88 88/89 89/90 90/91 91/92 92/93 93/94 94/95 95/96 96/97 97/98

6,000 5,000 4,000 3,000 2,000 1,000 0 −1,000 −2,000
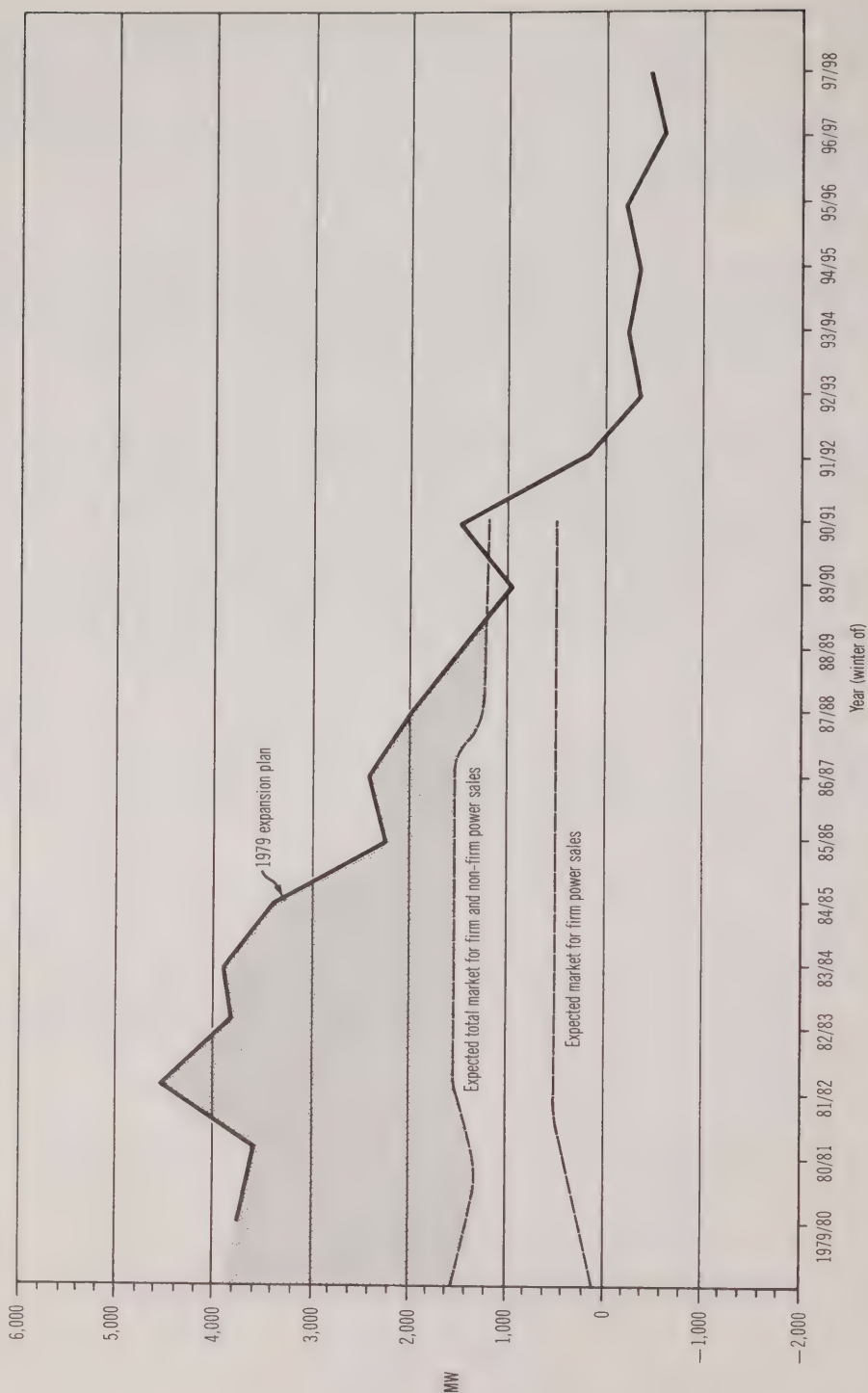
Note: Shaded area between excess capacity and potential export market demand is primarily oil-fired capacity.

Source: "1979 Review of the Generation Expansion Programme", Figures 8-1 (Alternative 6) and 15-1, Ontario Hydro, March 1979.

CHAPTER FIVE

Alternative Energy Investments: Three Examples

All energy-sector investments are capital-intensive. This characteristic is shared by conventional energy sources such as oil, gas, hydraulic, and nuclear as well as the conservation and renewable energy alternatives. They may differ in terms of technology, scale, and the existence of institutions that can facilitate their development, but in every case most or all of the cost of the flow of energy received, or saved, is the repayment, including interest charges, of the front-end capital investment.

Many advocates of conservation and renewable energy have drawn attention to the difference between the capital-intensity of the conventional energy sources and the labour-intensity of the alternatives. They have argued that solving the impending world petroleum shortage via a "soft path" will create more employment than pursuing the traditional centralized energy systems. However, two different phases of energy projects, their installation and their operation, are being confused by loose use of the terms capital-intensive and labour-intensive. While it may be purely a problem of semantics, it disguises a real implementation hurdle facing the alternatives to conventional energy forms.

In general, "capital-intensive" is applied to a production process that employs little labour directly but rather a large proportion of capital goods, that is, goods that embody prior labour input in combination with the natural resources utilized. Another characterization of a capital-intensive energy technology or conservation system is that it requires relatively little operation and maintenance labour to produce or save energy once it is in operation. This is as much the case for insulation, solar panels, windmills, co-generation, or photovoltaics as it is for hydraulic or nuclear power. Conservation and some forms of renewable energy require fewer operating or maintenance personnel than conventional systems. Biomass is perhaps the best example of a labour-intensive renewable energy source; a relatively high proportion of the cost of the energy is in the cost of husbanding the biomass.

Many so-called alternative energy options are only labour-intensive in the sense that the one-time capital expenditures on manufacturing the components and installing them may have had a high labour content. The issue of the relative employment-creating potential of the investment programmes in the energy sector is the subject of the next chapter.

The implementation problems facing capital-intensive conservation and renewable energy options are compounded by their decentralized nature. Two aspects will be discussed here: energy pricing, and financing.

Conventional energy sources, like the alternative sources, require a series of one-time capital programmes to construct their facilities, but, because they are integrated operationally, the option exists to average costs over the entire system — grouping together units completed 20 years ago with those just being built. Decentralized alternatives are isolated units, physically and temporally, and must be costed as such. For long-term energy planning purposes and economic efficiency it may be desirable for all energy forms to be priced at replacement (incremental, marginal) cost rather than to base market prices on average or accounting costs. Unless this is done, the alternative energy systems, which are of necessity costed incrementally, will have difficulty competing in the market-place until fossil fuels and electricity are costed in the same manner.

Capital-intensive energy systems are usually compared in two dimensions: their front-end capital cost (per unit of energy delivered) and the terms on which they may be financed. Conservation and renewable energy are often found to be cost-effective on the basis of the first criterion relative to conventional fuels, particularly when the latter are priced incrementally. But, when the pay-back period and the rate of return on investment desired by individual purchasers of decentralized conservation and renewable energy systems are taken into account, the choice frequently swings against them. A key challenge is to develop institutions and mechanisms to reduce the disparity in planning horizon between large energy corporations and individual energy consumers, so that critical investment decisions in the energy sector are made on a rational basis.

Individuals and small firms have a reputation for preferring investments that pay back their initial costs in less than five years. Indeed, even if they were motivated to look for 25- or 30-year financing, they would be unlikely to find it, and certainly not at interest rates comparable to the long-term bonds

floated by large private energy companies or public utilities. Almost by nature, an established institution is perceived by the financial community as having the stability and capability to undertake long-term ventures. The dilemma of the "small is beautiful", decentralized energy system advocate is that an investment that would be cost-effective if undertaken by a large organization may not be feasible for the small firm or individual citizen. The capital-intensity of conservation and renewable energy measures has yet to be paired with an institutional framework capable of implementing their long-term potential.

The dilemma is not insuperable. Assuming the present dichotomy between the nature of individual consumption decisions and energy-supply industry investment planning to be inherent and unalterable, the logical institution to act on behalf of society's longer-term interest is government. A recent submission to the U.S. Congressional Subcommittee on Energy came to the following conclusions regarding a mechanism to implement conservation and renewable energy (CARE) on a large scale:

> Since the [conventional energy] user's investment [in CARE] is compared with the average cost of energy, while the supplier [of conventional energy] deals with replacement cost, the user's decision is weighted against the purchase. To overcome this, some alternative financing arrangement seems to be necessary.

> One [possibility] is to introduce some form of national subsidy, such as the recently approved tax credit for homeowners and businesses. However, this applies only to particular classes of taxpayers and will not address the general need for making CARE investments attractive to the energy user.

> Another possibility would be to have the suppliers, especially the electric utilities, purchase (or loan the money for) conservation and solar installations. These investments would then be incorporated into the internal accounting of the energy producers. However, this would negate some of the main advantages of renewable energy systems, namely, their flexibility and amenability to control by the users. It would seem preferable to set up an alternative financing scheme which would accomplish the same end, that is, introducing a broad societal perspective into the financial arrangement, without transferring control to the current suppliers of energy. Since suppliers' investments will, in any case, be based on borrowed money which is repaid through payments by consumers, it should be possible, in principle, to devise mechanisms which would achieve this.[1]

Low-interest energy loans for CARE-type investments backed by the Ontario government could be made available through a government agency (an energy bank), a new Crown corporation, an existing Crown corporation (Ontario Hydro, Ontario Energy Corporation), or local banking institutions. Given the finite capital resources available to the provincial government, the combined demands of Hydro and CARE projects could lead to a competition for the use of government funds.

Our position is that energy projects, including conservation and renewables, that are cost-effective relative to nuclear power (costed at the annual capacity factor appropriate for the end use) when financed on the same basis, should be promoted. Several submissions to the Commission dealt with the avenues open to governments to accomplish this. In addition to the provision of equivalent cost capital funding, governments could:

- set standards, e.g., for building energy requirements
- apply tax incentives to encourage energy-producing or -saving investments, e.g., extremely rapid write-offs
- regulate relative energy costs to the consumer through a programme of taxes and subsidies (which could be offsetting, earn a surplus, or even run at a loss)

All three may discriminate for, or against, a subgroup of the population as a whole, either by increasing the first cost of particular capital goods (e.g., houses, cars, appliances) or by lowering individual long-run energy costs (e.g., in homes or production processes). The latter effects could be balanced by transferring some of the extra real income back to government through direct billing (perhaps included with the electricity bill) or by means of an income tax surcharge. In the former case, if government measures raise the cost of energy or energy-consuming capital goods, lower income groups could be compensated to some extent through an energy tax credit (similar to the present rent or property tax rebate for expenditures on accommodation).

With careful consideration and imagination, both federal and provincial governments could make better use of their ability to motivate alternative energy investments that are cost-effective relative to the major supply systems. Market forces are not effective when prices are regulated to suit short-term interests and when there are institutional barriers to competition on equal terms.

In this chapter, the cost-effectiveness of co-generation, residential insulation, and residential solar

space heating and water heating will be analysed under a variety of price assumptions and financing conditions. The price scenarios (detailed in Appendix C) include a mixture of average and incremental cost-based pricing. From Ontario's perspective, given the existing constitutional framework, the incremental cost of fossil fuel is, strictly speaking, the market price of an additional unit at the provincial border. This is not, as yet, the replacement cost or international price, though we consider scenarios that move in that direction. For electricity, average and incremental cost scenarios by end use are developed.

On the financing side, an attempt is made to contrast the implementation of alternative energy under public sector investment decision rules, like those applied by Ontario Hydro to nuclear stations, with those applied in typical individual or business practice. It becomes apparent that the differences between plausible price scenarios are less significant to the implementation potential for alternative energy options than the desired pay-back period and rate of return on investment.

While the three examples explored in this chapter could reduce the demand for electricity forecast by Ontario Hydro, no attempt has been made to calculate how much Hydro's capacity expansion programme could be reduced. There is a general difficulty in estimating the impact on Hydro's expansion programme of any measure that would displace loads Hydro would otherwise serve, because Hydro does not prepare end-use forecasts. In order to calculate the reduction in demand for centralized generation one would need to know the forecasted demand in that end use without conservation, its estimated contribution to peak-load capacity requirements, and the conservation or substitution Hydro has already assumed. All three pieces of information are important because, with an aggregated load forecast such as Hydro's, it can always be claimed that the peak-load reductions have already been accounted for without the outside observer having any means of verifying this.

For instance, the 1977 Middleton Associates study[2], prepared for the RCEPP, estimated the potential for conservation and renewable energies to substitute for electricity generation. It was accused by Hydro of double-counting. Ontario Hydro commented on the Middleton Associates report: "Since 1976, Ontario Hydro's load forecasts attempt to capture conservation effects. The subject report ["Alternatives to Ontario Hydro's Generation Program" prepared by Middleton Associates] double counts by subtracting these effects from a forecast in which allowance for conservation has already been made."

It is a difficult charge to prove rigorously. It may be noted that the reductions in Ontario Hydro's load forecasts in 1978 and 1979 did not quantify the reduction in load attributable to the increased implementation of conservation-type measures, leaving it unclear as to whether all the remaining potential for conservation in each end use of electricity has been taken into account by Hydro. This is a handicap for the present study, which has as one of its objectives to identify at what point the examples of conservation and renewable energy chosen become superior investments from society's or Ontario's perspective to a corresponding expenditure on increased Hydro capacity.

The Cost Effectiveness of Co-Generation

Co-generation may be defined as the simultaneous production of process-steam and electricity at an industrial site or, in some instances, at a university, hospital, or commercial firm. High costs for fossil fuels motivate large producers of process-steam to consider the generation of electricity as a by-product if the extra cost of generating a unit of electricity is competitive with the marginal source of base-load electricity from the grid. The use of the steam that is otherwise wasted can in some applications offset the increased unit costs of generators much smaller than would be considered economic by electricity utilities. Co-generation has become increasingly attractive since the 1973 oil crisis, because most utilities still use fossil fuels for base-load generation. If nuclear power were to totally displace fossil-fuelled units in supplying the base load, unit electricity costs at the margin would fall dramatically, relative to the future cost of fossil fuels for co-generation. In this case, where the nuclear capacity is already installed, a cost-benefit analysis would indicate only a temporary period of viability for co-generation. However, as will be demonstrated, when coal-fired co-generation is financed and fuelled under conditions equivalent to Ontario Hydro's, it remains a cost-effective way of meeting increments in base load for some time to come.

Co-generation has other, less readily quantifiable, advantages from a system planning point of view. Because each unit is relatively small (ranging up to 100 MW) and is fossil-fuelled, its lead time is very short compared with that of one of Ontario Hydro's nuclear stations. If the timing of co-generation

installations could be co-ordinated with the fluctuations in Hydro's load growth, the risk of over- or under-building the system because of the uncertainty in the load forecast could be reduced.

Methodology

To an industry generating its own electricity along with process-steam in a co-generating installation, the cost of electricity generation consists of extra capital and operating expenses above and beyond those that are attributable to producing the steam alone. Co-generation will be economically attractive if, over the assumed 30-year life of the plant, the savings on electricity costs relative to Hydro's expected rates, discounted by a satisfactory rate of return, at least repay the additional initial investment. The discounted savings minus the initial capital investment is called the net present value (NPV). The formula used to calculate this is presented in Appendix D. A zero or positive NPV at the discount rate the investor deems adequate, bearing in mind his costs of borrowing money to finance the project, will normally be the signal that the co-generation installation is cost-effective.

A high discount rate assigns little weight to savings some years off and focuses attention on the first few years of operation. A project with a zero NPV at a high discount rate will pay back the investment much more quickly than one that breaks even at a low discount rate.

In the private sector, the real (i.e., net of inflation) discount rate expected of investments in plant facilities ranges widely. In this study, three cases were selected — 10 per cent, 15 per cent, and 25 per cent — though more emphasis is placed on 15 and 25 per cent because there is evidence (see Hatsopoulos, et al., "Capital Investment to Save Energy", *Harvard Business Review*, March-April 1978) that industry expects a very quick return on co-generation, because it has a lower priority than investments that contribute directly to the expansion of output. In order to represent the benefits of co-generation as perceived by the businessman, annual net savings are taxed at a representative corporation's marginal rate (46 per cent). In addition, the reductions in corporate taxes resulting from a two-year rapid write-off of the investment as currently permitted in Ontario for "energy-conserving" equipment are credited to the co-generation investment.

Discount rates used by the public sector tend to be significantly lower than those in the private sector. Ontario Hydro's investments in, for instance, nuclear stations are currently designed to pay back in 30 years at a real discount rate of 4.5 per cent. Also, Hydro's net income is not subject to corporate tax. For Hydro to consider building and financing co-generation units as an alternative to centralized base-load generation, its net benefit analysis would normally apply these discount and marginal tax rate assumptions. Clearly, from this vantage point many projects would meet the NPV test under Hydro's investment criteria but would never be accepted under the decision rules used in the private sector.

But Ontario Hydro would also take a different view of electricity prices. While the private firm would calculate its savings as the difference between a projection of Ontario Hydro's published rate schedule and its internal electricity generation costs, Hydro would evaluate its net benefit by comparing the delivered cost of energy from, say, a nuclear unit at a given annual capacity factor (the probable short-run marginal system cost of meeting a large industrial load) with the corresponding costs of co-generated electricity. Thus, in our study, Hydro's incremental cost of base-load electricity is paired with a zero tax rate and a 4.5 per cent real discount rate, while expected market prices are used with a 46 per cent marginal tax rate and a 15 per cent real discount rate in order to contrast the two financing environments.

In evaluating whether society is better off to finance co-generating units or nuclear stations with provincially guaranteed debt capital, the two alternatives should be presented using the same parameters. That is, either public or private sector criteria should be applied consistently. Only when no institutional arrangements can be found to finance co-generation on a public sector basis would the difference between the incremental cost of centrally generated electricity financed under public sector conditions and electricity from co-generation financed under corporate conditions be a valid estimate of the NPV to society of the preferred project.

In this study, it is assumed that, by paying Ontario Hydro's stand-by charge on an annual basis, industrial co-generators will pay for Hydro's expenditures in providing back-up facilities. In his paper to the "Economics of Industrial Co-Generation of Electricity" seminar in December 1978, H.C. Palmer of Ontario Hydro stated: "The monthly standby charge of $8 to $10 per kilowatt per year specifically provides the customer with the standby service option if and when it may be required.... Ontario Hydro's regular monthly demand/energy rate is applied in addition to this standby charge, should the

customer in fact draw some standby power in any one month"[3]. In order to simplify this analysis it has been assumed that the cost of replacement energy from Ontario Hydro is equal to the cost of electric energy produced by the industrial customer.

Capital and Operating Costs. This study considers two basic types of co-generation investments: the installation of co-generation capability as part of a new plant and the retrofitting of co-generation capacity in an existing plant. Opportunities for retrofitting have been divided into three categories: those not technically feasible (10 per cent of the total capacity), those requiring new steam plants at a premium above new installation cost of 60-75 per cent (about 40 per cent of total capacity), and those for which costs are roughly comparable to new installations. This approach is designed to approximate a continuum from zero cost penalty for retrofit to cases where retrofitting is technically not possible. When a distinction is drawn between the cost-effectiveness of new and retrofit units in the discussion that follows, the retrofit units referred to are only those requiring new steam plants.

For new or retrofit co-generation, coal and natural gas boiler fuels were assessed for units of 5 MW, 10 MW, 20 MW, and 40 MW, operating at annual capacity factors of between 65 per cent and 80 per cent. Capital costs per kilowatt decrease with the size of the unit from $700 per kilowatt at 5 MW to $325 per kilowatt at 40 MW for a new gas-fired boiler. Coal capital costs are estimated to be twice those of gas due to the extensive coal-handling facilities required.[4] Where gas is not available, it is assumed for simplicity in the penetration studies that residual fuel can replace gas for a similar capital cost and fuel price.

Operating costs are constant throughout the analysis, though fuel costs depend on the price scenarios described in Appendix C. The details of capital and operating costs are summarized in Table D.1 of Appendix D.

In general, when the front-end unit costs are high, a low discount rate improves the viability of the project. This means that the Ontario Hydro financing assumptions encourage the use of coal as a fuel and the use of more retrofitted units and small units. At higher discount rates, gas is preferred because of its low initial capital costs. However, real gas costs are assumed to increase at an exponential rate in all three scenarios, while in all except the high electricity price scenario base-load electricity costs are either fairly constant or declining. This results in quite a few examples in which gas-fired co-generation is cost-effective for installation in the 1980s but no longer in the 1990s. Also, increasing the annual capacity factor (ACF) of a co-generation unit using gas may worsen its economics. The relative abundance of coal, which prompted the assumption of constant real coal prices in the long run, means that coal-fired generation may not face this problem.

If nuclear power would otherwise meet the load served by co-generators, and if nuclear capital costs remain relatively constant in real terms, as Ontario Hydro assumes, it will not make much difference to the economics of co-generation whether base-load electricity prices are based on average costs or on long-run marginal costs. In either case, co-generation will face serious competition in the 1990s. With the prospect of constant real electricity rates and increasing real fossil-fuel prices, the attractiveness of this alternative to centralized generation declines over time.

Results

The details of the year-by-year NPV calculations for each permutation of installation size, fuel type, discount rate, electricity price scenario, fuel price scenario, tax assumption, and new or retrofitted unit choice will be spared the reader. The results form part of the RCEPP's papers, which include the background notes for this chapter prepared by Middleton Associates. Only a summary of the major findings will be given here.

Using Ontario Hydro financing criteria and electricity prices based on estimates of Hydro's short-run marginal cost (varying with ACF), our analysis found that all types of co-generation units are cost-effective except 5 MW retrofit coal under a medium or high fuel-price scenario. Only a few small retrofit units require pay-back periods of more than 20 years, and most cases fall in the 5-15-year pay-back range. The most cost-effective units are large gas-fired boilers, which offer pay-backs as short as three or four years even when electricity prices are low.

From the perspective of a firm seeking a 15 per cent real rate of return on investment, if the expectation is that real electricity prices will continue to increase, new units as small as 5 MW gas or 10 MW coal would be attractive, as well as retrofit installations down to 10 MW in the case of gas but only 40 MW for coal. When the low or medium electricity scenarios (see Appendix C for detailed assumptions) are followed, the minimum new unit size that is economic is 10 MW for gas or 20 MW for coal, but the only

feasible retrofitted units are 40 MW gas-fired. When the rate of return is increased to 25 per cent, and only if gas prices do not follow the high growth rate, a new 20 MW gas installation would be cost-effective if installed up to the mid 1980s, but not thereafter. A 40 MW unit could be installed economically several years later. No coal units yield a 25 per cent real rate of return unless electricity prices follow the high scenario.

The disparity in viability between co-generation investments depends primarily on the financing conditions. This becomes apparent when the proportion of the potential market that might feasibly be installed is estimated.

Scenarios of Installed Co-Generation Capacity to the Year 2000. An estimate of installed co-generation capacity by the year 2000 proceeds in two steps: first, the total market potential is estimated, and then the results concerning cost-effectiveness are applied to the implementation rate in each segment of the potential market. The total potential capacity of installations by the year 2000 may be broken out as follows: the capacity already installed, the retrofit potential that exists as of 1980, and the potential capacity of new installations in the years 1980-2000. The potential for new installations has, for want of a better solution, been estimated by extrapolation from the existing total market (i.e., installed plus retrofit potential in 1980) using a fairly arbitrarily derived growth rate. This method has been used by both Ontario Hydro and the firm of Leighton & Kidd in the studies referred to below. The projection of the total potential market is therefore sensitive to the estimate of the retrofit potential and the growth rate. Two cases will be discussed here, based on different Ontario Hydro estimates of co-generation potential. Then three plausible implementation examples, chosen to characterize the range of probable outcomes, will be applied to the higher estimate of market potential.

The Potential Market for Co-Generation. As the Ontario Hydro estimates of co-generation potential are based on different interpretations of the work that Leighton & Kidd undertook for the RCEPP,[5] it will be useful to review some of the Leighton & Kidd findings in order to put the Hydro estimates into perspective.

Leighton & Kidd undertook a survey of Ontario industrial steam generating capacity in 1977. They found 510 MW of co-generation capacity already installed in the province. Basing their estimates on the survey, Leighton & Kidd placed the technical potential ("upper limit potential") in plants existing in 1977 at 49,618,000 pounds per hour of maximum steam demand.[6] They assumed an installed capacity of 60 kW per 1,000 pounds per hour of maximum steam demand, which yields a potential of 2,950 megawatts. Then, postulating a 5 per cent annual growth, they put the 1985 co-generation potential at 4,538 MW.

Stating that "it would be neither practicable nor desirable to achieve this upper limit"[7], Leighton & Kidd established what they termed a "possible target potential" for both existing and future plants, while acknowledging that these targets were not based on a firm analytical foundation: "It is not possible in this preliminary study to establish a practicable target in definitive terms, but an attempt will be made to do so on a judgemental basis."[8]

These potential implementation targets were established as percentages by size of installation (see Table 5.1). Using these percentages, Leighton & Kidd developed possible target potentials of 1164 MW for existing plants, 921 MW for future plants (to 1985), and a total potential to 1985 of 2,085 MW.

Table 5.1 The Target Potential for Co-generation

Capacity (K)	Target potential Existing plants	Future plants
K > 500,000 lbs/hr	75%	100%
500,000 > K > 100,000 lbs/hr	40%	75%
K < 100,000 lbs/hr	10%	40%

Source: Leighton & Kidd Limited, "Report on Industrial By-Product Power", May 1977, p. 14.

Ontario Hydro has contended that 50 kW per 1,000 pounds of steam is a more realistic estimate of potential than the 60 kW used by Leighton & Kidd. (The Hydro figure has been used in evaluating the cost-effectiveness of co-generation discussed above.) Table 5.2 shows the impact on the Leighton & Kidd estimates of assuming 50 kW rather than 60 kW.

Table 5.2 Leighton & Kidd Target Potentials

Leighton & Kidd category	Co-generation capacity (kW/1,000 lbs. of steam) 60[a]	50[b]
Upper limit potential (1977)	2,950	2,458
Upper limit potential (1985)	4,358	3,632
Target potential – existing plants	1,164	970
Target potential – future plants (to 1985)	921	768
Total target potential (to 1985)	2,085	1,738

Sources:
a) Leighton & Kidd Limited, "Report on Industrial By-Product Power", May 1977, pp. 13-14
b) Leighton & Kidd estimates modified assuming 50 kW/1,000 lbs. of steam.

Case 1. In its response to Middleton Associates' *Alternatives to Ontario Hydro's Generation Program,* Ontario Hydro put forward a view of the likely growth of the potential for co-generation in the province.[9] Hydro placed the 1977 co-generation potential at 1,220 MW, 510 of which was already in place, and postulated a 2 per cent annual growth rate in this potential. Assuming that this growth rate applies to both existing and potential installations in the 1977-80 period, and on to the year 2000, total potential installed capacity in 1980 and 2000, split out by unit size using the distribution among capacity sizes as in Leighton & Kidd's "target potential-existing plants", is shown in Table 5.3.

Table 5.3 Case 1: Co-generation Market Potential in 1980 and 2000

Capacity (K)	Market share	Installed (1980)	Potential (1980)	Subtotal (1980)	Additional potential (2000)	Total (2000)
K ≥ 25 MW	69	325	568	893	453	1,346
25 MW > K > 5 MW	24	178	133	311	154	465
K ≤ 5 MW	7	38	53	91	48	139
Total	100	541	754	1,295	655	1,950

Source: RCEPP.

Case 2. D.A. Drinkwalter, Chief Economist of Ontario Hydro, included estimates of Ontario's co-generation potential in a paper presented to the "Economics of Industrial Co-generation of Electricity" seminar[10]. Using largely the Leighton & Kidd survey, but also including some non-industrial installations such as universities, hospitals, and commercial firms that operate steam plants to provide heating during the winter months, Drinkwalter estimated the 1977 total potential to be 1,560 MW. He then "decided to assume that the growth rate of potential capacity would be half that of industrial output". The forecast of industrial output yielded growth rates of 2.3 per cent in 1977-85 and 2.1 per cent in 1985-90. (The 2.1 per cent growth rate will be used for the 1990-2000 period as well.) These growth rates are applied, as in the previous case, to the total market (installed plus potential) in 1980 to estimate the additional potential to the year 2000. The market share of the various unit sizes was taken to be the same as in Drinkwalter's 1977 estimates. Table 5.4 summarizes the potential market under these assumptions.

Table 5.4 Case 2: Co-generation Market Potential in 1980 and 2000

Capacity (K)	Market share (potential)	Installed (1980)	Potential (1980) With new steam plants	Without new steam plants	Total	Additional potential (2000)	Total potential (2000)	Total installed (2000)
K ≥ 25 MW	51%	325	346	506	852	584	1,436	1,761
5 MW < K < 25 MW	22%	178	176	191	367	252	619	797
K ≤ 5 MW	27%	38	158	293	451	310	761	789
Total	100%	541	680	991	1,670	1,146	2,816	3,357

Source: RCEPP estimates derived from "Relationship of Industrial Generation and Ontario Hydro's Expansion Program", D.A. Drinkwalter, Ontario Hydro, December 1978.

Implementation. Estimates of the proportion of the potential market that might actually be installed depend on the viability of the individual co-generation units under specific sets of assumptions. Implementation rates for new and retrofitted installations will be estimated by unit size, given fuel price,

and financing assumptions. Three plausible examples have been selected to demonstrate the sensitivity of the implementation rates to expectations of future energy prices and the nature of the financing arrangements.

A low case, Example 1, assumes that co-generation investments should yield a 15 per cent real, after tax, rate of return when industry expects electricity prices will follow Ontario Hydro's projection of constant real electricity prices on average to the year 2000, while natural gas prices reach 100 per cent BTU equivalence with oil at $25 per barrel (1978 dollars) in 2000.

A high case, Example 2, could be realistic if co-generation investments were treated the same way as Ontario Hydro capital expenditures, that is, requiring a before tax real rate of return of 4.5 per cent. The electricity price scenario is an estimate of Hydro's short-run marginal cost for base-load energy. Under these conditions, as noted in the cost-effectiveness section above, it does not matter which boiler fuel scenarios are chosen. This scenario could still be an underestimate, should real nuclear power costs escalate significantly (e.g., by more than about 20 per cent by the 1990s). The cost of components from a contracted nuclear industry or the need for additional expenditures to enhance the safety of the reactor system could drive nuclear costs up. Base-load energy prices could be significantly understated if the central generating alternative turned out to be coal-fired power.

A third example, which will be described only briefly, maintains the business financing assumptions of Example 1 but considers the possibility of significant base-load generation being met by coal-fired power, so that the high electricity price scenario is expected. The outlook for natural gas is considered sufficiently favourable that the medium-price assumptions (85 per cent BTU equivalence with $25 per barrel of oil (1978 dollars) in the year 2000) are adopted for planning.

New Installations. Example 1 gives a pessimistic view of co-generation implementation from a business perspective. Under the assumptions outlined, only units of 25 MW or larger capacity would be installed, and then only in the years before 1990. None of the smaller units appear to be economic. The penetration into the potential market of 25 MW or larger units was estimated to be 40 per cent.

In Example 2, with much more favourable financing conditions, all installations in the two target capacity categories make economic sense under the range of price and capacity factor assumptions made. The proportion of the less than 5 MW capacity category making economic sense is less clear. All of the systems analysed yielded positive net present values. However, only the upper end of this capacity group (5 MW) was analysed; no smaller installations were examined. In addition, no cases of significantly lower capacity factors were analysed. Consequently, in order to allow for the possibility that a significant proportion of the smallest category would not prove to be economic, an implementation rate of 60 per cent for the category has been selected.

In Example 3, all gas co-generation units yield a positive NPV at a 15 per cent real discount rate, though pay-back periods range from 10-20 years for smaller units (Table 5.5).

Table 5.5 Implementation of New Co-generation Installations

Capacity (K)	Proportion implemented		
	Example 1	Example 2	Example 3
K ≤ 5 MW	0%	60%	60%
5 MW < K < 25 MW	0%	100%	100%
K ≥ 25 MW	40%	100%	100%

Source: RCEPP.

Retrofit Installations. The Retrofitting of existing commercial and industrial facilities may be substantially more expensive than the installation of co-generation during initial construction, especially when new steam plants are required.

Under the assumptions of Example 1, the analysis of the cost-effectiveness of co-generators requiring new steam plants demonstrated that few, if any, of the largest class (i.e., greater than 25 MW) and none of the smaller categories would find retrofitting attractive. The proportion of retrofits having costs similar to new installations, estimated to be about 50 per cent of total retrofit potential, would have the same likelihood of installation (40 per cent) as is assumed for new units. As a result, penetration of the large retrofit co-generation plant category was set at 20 per cent.

In Example 2, all technically feasible retrofit installations were found to be economic with the exception

of units smaller than 5 MW. In this category, 58 per cent of the potential not requiring new steam plants (60 per cent) were expected to be implemented, i.e., 35 per cent of the total potential.

In Example 3, no 5 MW or smaller units would be expected to be retrofitted. About half of the cogeneration units requiring new steam plants in the next capacity category (5-25 MW) would likely be viable. The proportions implemented in each capacity category for all three examples are summarized in Table 5.6.

Table 5.6 Implementation of Retrofit Co-generation Installations

| Capacity (K) | Proportion implemented | | |
	Example 1	Example 2	Example 3
K ≤ 5 MW	0%	35%	0%
5 MW < K < 25 MW	0%	90%	70%
K ≥ 25 MW	20%	90%	90%

Source: RCEPP.

Table 5.7 Co-generation Capacity Installed to the Year 2000 — Example 1, Based on Business Financing Assumptions, High Boiler Fuel Prices, and Low Hydro Rates

| Size | Potential (MW) | Penetration | | Capital cost (millions of 1978$) | |
		(%)	(MW)	All coal	All gas
New:					
K ≥ 25 MW	584	40	234	153	77
25 MW > K > 5 MW	252	0	0	0	0
K ≤ 5 MW	310	0	0	0	0
Total	1,146		234	153	77
Retrofit:					
K ≥ 25 MW	852	20	170	194	97
25 MW > K > 5 MW					
K ≤ 5 MW	451	0	0	0	0
Total	1,670		170	194	97
Total potential installed			404		
Installed (1980):					
K ≥ MW	54	100	541		
Total new, retrofit and installed			945	347	174

Source: RCEPP.

Table 5.8 Co-generation Capacity Installed to the Year 2000 — Example 2, Based on Hydro Financing Assumptions[a]

| Size | Potential (MW) | Penetration | | Capital cost (millions of 1978$) | |
		(%)	(MW)	All coal	All gas
New:					
K ≥ 25 MW	584	100	584	380	190
25 MW > K > 5 MW	252	100	252	221	110
K ≤ 5 MW	310	60	186	260	130
Total	1,146		1,022	861	430
Retrofit:					
K ≥ 25 MW	852	90	767	877	439
25 MW > K > 5 MW	367	90	330	518	259
K ≤ 5 MW	451	35	158	357	178
Total	1,670		1,255	1,752	876
Total potential installed			2,277		
Installed (1980):					
K ≥ 25 MW	54	100	541		
Total new, retrofit and installed			2,818	2,613	1,306

Note a) Hydro base-load short-run marginal cost used for electricity prices.
Results reasonably insensitive to boiler fuel price scenario.
Source: RCEPP.

Table 5.9 Co-generation Capacity Installed to the Year 2000 — Example 3, Based on Business Financing Assumptions, High Electricity Prices, and Medium Gas Prices

Size	Potential (MW)	Penetration (%)	(MW)	Capital cost (millions of 1978$) All coal	All gas
New:					
K ≥ 25 MW	584	100	584	380	190
25 MW > K > 5 MW	252	100	252	221	110
K ≤ 5 MW	310	60	186	260	130
Total	1,146		1,022	861	430
Retrofit:					
K ≥ 25 MW	852	90	767	877	439
25 MW > K > 5 MW	367	70	257	403	201
K ≤ 5 MW	451	0	0	0	0
Total	1,670		1,024	1,280	640
Total potential installed			2,046		
Installed (1980):					
K ≥ 25 MW	54	100	541		
Total new, retrofit and installed			2,887	2,141	1,070

Source: RCEPP.

Co-Generation Capacity Installed by the Year 2000

Tables 5.7 to 5.9 summarize the three examples that have been developed in the preceding sections. The total additional co-generation capacity likely to be installed between 1980 and 2000 ranges from about 400 MW in Example 1 (Table 5.7) to 2,280 MW in Example 2 (Table 5.8). The case in which business expects high future electricity costs but takes an optimistic view of natural gas prospects, Example 3, leads to the same penetration of the new installation market as in Example 2 (Table 5.9). It has lower implementation rates for the smaller retrofit opportunities but ends up only 230 MW below Example 2.

The total capital cost incurred in installing co-generation units may vary widely. The cost of coal-fired units in Example 2 is eight times that of the coal-fired units installed in Example 1. A public sector mini-utility installing only coal-fired units could have cumulative capital requirements of about $2.6 billion (1978 dollars — see Table 5.8) by the turn of the century. Industrial firms installing gas-fired co-generation may spend only $175 million (Table 5.7).

A. Juchymenko of Ontario Hydro has proposed the creation of a co-generation firm that would take Hydro's place in joint ventures with industrial companies interested in installing co-generation facilities.[12] A "third party" co-generation firm would probably find a 15 per cent real after tax rate of return satisfactory, whereas industrial firms that view co-generation as an investment diverting their scarce capital resources from more productive uses often demand a higher return. In these cases, Hydro's concept would have a larger market potential than industry acting by itself. However, Examples 1 and 3 of co-generation installation prospects indicate that the installed capacity of a co-generation firm in the year 2000 could vary widely, depending on the expectations regarding energy price increases. A publicly financed co-generation utility whose investments were expected to earn a relatively low rate of return would be able to justify a similar or higher level of co-generation capacity without resorting to controversial scenarios for electricity costs and fossil-fuel prices.

Reducing Residential Heat Loss

There are two principal categories of heat loss from a home: the cooling of the interior due to the infiltration of air from outside the house, and the conduction outwards of internal heat through the attic, basement, walls, and windows. This section will first review key heat conservation measures appropriate for new and existing houses and then examine the contribution of improved infiltration control and higher levels of insulation in new dwellings.

The rate of air infiltration in new homes may be reduced substantially by meticulously applying a vapour barrier to the house and sealing doors and windows carefully. With high standards of workmanship, a house can be so tightly sealed that air changes, normally involving about half the volume of the air in the house per hour, could be cut to one-tenth of that amount. Infiltration control would substantially reduce heating requirements but brings with it several undesirable by-products. Odours would accumulate and humidity control would be difficult. To solve these problems, air-to-air heat

exchangers have been developed that are quite simple in design and serve to recover a large portion of the warmth leaving the house by pre-heating the incoming cold air with the outgoing warm air. This and other one-time investments in improving home energy efficiency will be discussed in more detail below.

In existing homes, which will still constitute between two-thirds and three-quarters of the housing stock in Ontario in the year 2000, air infiltration may be sizably reduced by the judicious caulking and sealing of cracks and areas around doors and windows. Particularly in oil- and gas-heated homes, this low-cost measure could be the best single investment in residential energy saving and should be promoted on a wide scale as a top priority in a retrofit programme. An army of summer students could probably make great inroads in this labour-intensive activity. That it is not examined further here is no reflection on its importance.

Reduced net heat loss due to conduction through the skin of a new house may be achieved in numerous ways. The orientation and architecture of the home may be designed to maximize passive solar gain, insulation levels may be increased throughout the dwelling, and the heat loss through windows can be reduced by adding layers of glass or shutters. These are probably the major improvements that could be made to the 900,000 or so non-apartment homes likely to be built in Ontario in the next 20 years.

In the analysis of feasible energy savings, passive solar gain is conservatively estimated to be capable of contributing savings of about five per cent of total annual home heating needs without incurring extra capital cost.[13]

Determining the appropriate level of insulation for the attic, exterior walls, and basement is the subject of much of this section. The effectiveness of insulation is indicated by the "R" factor, which measures the resistance of the insulating material to the transmission of heat. The higher the R value, the lower the heat loss per square foot per hour per degree day. The hypothesis tested was that the optimal level of insulation would be highly sensitive to the pay-back period required by the home-owner on the incremental investment and to the expected future cost of energy for home heating. Insulation will usually last as long as the house itself.

Our principal finding was that, if the house-builder and the buyer can be persuaded to view extra expenditures on insulation as a long-term investment, insulation levels of nearly twice those currently installed in the typical house would be economic. Once a 30-year pay-back on the last R value installed is satisfactory to the investor, it becomes apparent that the optimal level of insulation is no longer extremely sensitive to the precise assumptions made about the future cost of fuels for home heating.

Given the relatively high cost of subsequent retrofits, there is a strong incentive to find a combination of housing standards and financing arrangements that will ensure that the new housing stock is well insulated for an era of high-cost energy.

Modifications to the insulation levels in the walls of existing houses (especially those of brick construction) are quite costly. On the other hand, retrofitting insulation in the attic is fairly straightforward and clearly cost-effective now. Basements fall somewhere in between. Federal government support for such retrofitting to a maximum of $500 is being given now through the Canadian Home Insulation Programme (CHIP). This section includes estimates of the optimal R values for the attic of a typical Ontario house heated by oil, gas, or electricity. The total capital cost of feasible new and retrofit insulation investments over the period 1980-2000 is estimated at the end of the section.

Minimizing heat loss through windows is the remaining avenue for reducing outward conduction of home heat. The technical solution appears to be to do with as few windows as possible, except on the south-facing side of the house. However, whether for the windows in existing or new residences, the consultants to the RCEPP were not convinced of the cost-effectiveness of either triple-glazing or R 10 shutters (which could be closed during the night to help reduce heat loss) in comparison with double-glazing. A short note summarizing their observations appears in Appendix E.

Controlling Air Infiltration

The optimizing of air infiltration in a new home is achieved in two stages. First, air changes are reduced from roughly one-half of the volume of air in the house each hour at current housing standards[14] to 0.05 complete air changes per hour by applying a 6 mil polyethylene vapour barrier on the ceiling and walls so carefully that it does not become perforated. Then, the air changes per hour are increased again to a more comfortable 0.25 per hour, in a controlled fashion, by directing the incoming air past the outgoing air through an efficient heat exchanger. The Saskatchewan Research Council has investigated this

combination thoroughly and has applied it in their demonstration project, the Saskatchewan House. Contractors in Regina and Saskatoon, and by now elsewhere in Canada, have used this technology in commercial housing developments. The main problem with the heat exchanger, one that should be solvable, appears to be frosting on the exchanger as a result of condensation build-up in winter.[15]

A researcher with the Saskatchewan Research Council estimates that the extra cost of installing the vapour barrier (mostly labour) and the heat exchanger is about $500 per house. He believes that that figure could be cut in half if the exchanger were mass-produced.[16] This study has assumed the higher figure.

Any analysis of heat loss is conditional on the outside temperature. The harshness of the winter climate is measured by the annual number of degree days recorded in the area. A degree day is defined as the difference between 65°F (18°C) and the minimum daily temperature. Throughout the analysis of air infiltration and insulation level, 7,500 Fahrenheit degree days (4,200 Centigrade degree days) is taken to be typical for Ontario. Malton, Ontario, traditionally records very close to this number of degree days.

The energy savings in a 7,500 Fahrenheit degree day weather zone for a 15,000 cubic foot (425 m^3) home that is tightly sealed and uses an air-to-air heat exchanger is estimated to be 16 million BTU per year. This is the net effect after 0.8 million BTU are lost due to the less than complete efficiency of the heat exchanger and after subtracting 5 million BTU that are consumed by the fan assisting the air circulation. At this rate of energy savings, and using a 5 per cent real discount rate, a $500 investment in a heat exchanger and a tight vapour barrier would pay back the investment in four to six years. The range is due to the choice of fuel-price scenario. As fuel prices increase over the years, the pay-back will, of course, be faster. If new-home owners require a still shorter discounted pay-back period, the implementation of this conservation option would be limited. [1 million BTU (British Thermal Units) *equals* 1.055 GJ (gigajoules)]

Insulation Levels for New Houses

A higher level of insulation is so frequently recommended in hew houses as an energy conservation measure that its potential contribution to the energy supply problem is perhaps overstated. In determining how much insulation may be cost-effective from the home-owner's point of view, both energy price expectations and financing options need to be taken into account. If the energy price outlook is such that the savings from higher levels of insulation appear to the home-owner to be clear-cut, there may be little concern over ways to find financing for the incremental front-end cost. On the other hand, if the perception of the home-buyer is that the extra dollars expended on the house should have an ultra quick pay-back, no financing arrangement may make the difference. In this circumstance, building standards may be a more effective means to ensure that society's best long-term interest will be served.

In this section, we will describe the methodology used to select the highest increment of insulation that is cost-effective (the optimum R value), and then go on to estimate the total potential energy savings from insulation and the total cost of home energy conservation measures for Ontario. The optimum R value may be defined as the insulation level beyond which any further expenditure on insulation is not recovered in energy savings, as perceived by the home-owner as he makes his decision to insulate. The calculations cover the economics of insulating the attic, exterior walls, and the basement of a non-apartment residence. The implications of three price scenarios were investigated for natural gas (likely to be the heating fuel in 75 per cent of new housing starts) and for electricity (assumed to take the rest of the market). Also, a range of pay-back periods, discount rates, and financing conditions were considered.

The effect of applying Ontario Hydro investment decision rules for thermal generating stations is also investigated, that is, a 30-year pay-back period at a 5 per cent real discount rate is applied to incremental insulation levels. To give a flavour of the findings: for electric space heating, the results indicate that shortening the preferred pay-back period to five years from 30 years has a much greater impact on the estimate of the optimum R value than the practice of using average cost pricing rather than long-run marginal cost pricing as the basis for electricity rate design. When the investor does take a long view of additional insulation, the difference between the two rate structures for electricity could motivate a 30 per cent increase in R factor, whereas acceptance of a 30-year pay-back, rather than a five-year one, would double the R factor.

Determining the Optimum Level of Insulation. The optimum R values are calculated using the methodology applied by the National Research Council of Canada to derive the recommended insulation standards for new buildings.[17] The mathematical formula is given in Appendix E. The optimum R formula may be applied to attic insulation without further qualification, but its use for exterior walls and basements below grade is more controversial. Appendix E notes some of these issues (see footnotes to Figure E.1).

It is important to emphasize that determining the pay-back for the last R of insulation installed is not indicative of the pay-back on the total amount of insulation in the home. The ability of an additional R of insulation to reduce heat loss decreases exponentially. Doubling insulation from R10 to R20 cuts the initial rate of heat loss in half. However, increasing insulation by another R20 (to R40) only reduces the heat loss by half the amount achieved by the first R10 increment from R10 to R20. The greatest return on insulation investment is to be had in the first doubling of insulation levels above current practice. Doubling again, say, up to standards of the Saskatchewan House, is more difficult to justify. The pay-back in going, for example, from R37 to R38 in an attic may take 30 years, but the pay-back on the entire R38 may turn out to be as little as four years. Our results showed that the first R10 of insulation in an attic of an electrically heated home typically would pay back in less than a year, R20 in less than two years, and R30 in about three years.

Apart from reflecting the decreasing return on insulation level, the optimum R calculation is sensitive to the assumptions concerning the degree days of the weather zone, the rate at which energy prices increase and savings are discounted, and the availability of mortgage financing for the installation costs. We will look at these factors in turn.

The optimum R value varies as the square root of the number of degree days. To illustrate, consider an example in which the number of annual degree days in a region is 10 per cent smaller than the typical value for Ontario. In this instance, the optimum R would be reduced by about 5 per cent. A doubling in the number of annual degree days would increase optimal insulation levels by about 40 per cent.

The real energy price increase scenario, the economic life (i.e., the number of years the investor allows for the insulation to pay back in discounted energy savings – usually much shorter than its physical life), and the discount rate all enter the optimum R calculation together when the present value of the life-cycle energy savings is determined. This quantity is labelled "LCC_E" in the formula in Appendix E. It represents the benefit of extra insulation to an investor, as he perceives it in the present, derived from the stream of annual energy savings that he will receive over the economic life of the insulation after his future energy savings are discounted. When future benefits are given the same value as those occurring in the present (i.e., when the investor has a zero discount rate), all the energy savings are included in determining the optimum R, regardless of when they take place. When a 5 per cent discount rate, a 30-year economic life, and no energy price escalation are assumed, the effect of discounting on present value is as if only about half of the energy savings took place. Changing the discount rate to 25 per cent, but keeping the other assumptions the same, only credits one-sixth of the life-cycle energy savings to the determination of the optimum R value.

Keeping the discount rate constant, but shortening the economic life of the insulation investment, has a similarly dramatic effect on the energy savings used to determine the optimum R. The planning horizon that the investor works with is analogous to his choice of discount rate.

The mathematics of the optimizing formula are such that escalating energy prices serve to offset the impact of high discount rate assumptions. For example, if energy prices escalate at 5 per cent per year, while the benefit stream is discounted at 5 per cent annually, the life-cycle energy savings will be the same as if no escalation and no discounting had occurred. As one would expect, the faster energy prices increase, the higher the level of insulation that is appropriate.

In our scenarios, the choice of high discount rates and short planning horizons, both of which act to reduce the amount of insulation installed, dominate the increase in installation levels as a result of higher energy prices. The most rapidly rising energy price scenarios considered here, high oil and electricity, increase at a real annual average rate of 2.6 per cent to the turn of the century and are no match for 10 per cent and 25 per cent real discount rates. When energy price escalation and discounting scenarios are combined over a 30-year life, the energy savings component of the optimum R formula varies roughly four-fold and results in the R value of insulation installed differing by a factor of about two. This is demonstrated in Appendix E, Table E.1. In 1980, under a 30-year pay-back, the

medium electricity scenario would call for R19.2 in the attic when a discount rate of 25 per cent is applied, but for R38.1 if 5 per cent was assumed.

Long-term, i.e., mortgage, financing goes a long way towards neutralizing the insulation-suppressing effect of high discount rates. The rate of return from the investor's point of view is now calculated in relation to the additional mortgage payments, not to the initial lump sum invested. Table E.1 shows the optimum R values for attic insulation when energy savings are discounted at 25 per cent, but a 30-year mortgage at a 4 per cent real (i.e., net of the rate of inflation) rate of interest is available. Assuming that electricity prices follow the medium scenario, an increase in the R value in the attic to 37.7 would pay back in 30 years. The incremental investment to R30.6 would pay back in five years. A 4 per cent real interest rate on the mortgage may be considered too high. The impact of a 2 per cent real interest rate would be to increase the R value installed by about 15-20 per cent.

The example of attic insulation appropriate for the Toronto area (6,827 degree days), presented in Table E.1, indicates that relying on prices in the market-place to guide home-builders and -buyers is not enough to ensure that insulation installed will match the level justifiable were Ontario Hydro's financing rules to apply. The ability to finance the insulation investment as part of the mortgage of the house helps considerably: if the buyer wishes his additional mortgage payments to equal his energy savings within five years, he would insulate to about 80 per cent of the optimum R corresponding to a 30-year pay-back (see columns 5 and 6 of Table E.1). Without a mortgage he would only install half of the insulation warranted (compare columns 3 or 4 with columns 5 or 6, respectively, in Table E.1). If Hydro is installing generating capacity to meet electric space-heating loads while its customers are buying homes insulated to a level consistent with a much shorter pay-back period, a misallocation of society's resources will occur. This principle could be built into the determination of insulation standards in the Ontario Building Code.

Potential Energy Savings in Ontario from Higher Insulation Levels and Air Infiltration Control

The "optimum R" calculation, as has been demonstrated, is not an absolute standard but is conditional on a variety of assumptions that determine the costs and benefits of insulation. Any single standard selected will therefore reflect a number of judgements. In aggregating to find the potential energy savings for the province, one insulation level per price scenario per house segment was selected. It is the level that would be installed if conditions similar to Ontario Hydro's are assumed: a 30-year pay-back at a 5 per cent real discount rate. This was felt to represent a desirable target for Ontario.

In order to obtain an estimate of the potential for reducing house-heating energy needs that could be derived by insulating non-apartment residences at the level made cost-effective by each energy price scenario, this study proceeded as follows:

1. The dimensions of a typical Ontario dwelling were estimated (Table E.2).
2. Two sets of assumptions about the insulation levels in new homes were made (Table E.3).
3. The year-by-year energy savings per house, corresponding to the difference between the insulation level that is economically justified in a given year and the new house insulation levels, were calculated (Tables E.4 to E.9).
4. This figure was multiplied by the number of housing starts projected for that year (Table E.10).
5. Annual energy savings and costs were aggregated for 1980-2000.

At step 4, the impacts of improved air infiltration and passive solar design were included. The estimate of energy saved is, at this stage, only for tertiary energy, that is, for the energy distributed to the required part of the house after conversion of the energy source to heat. Electricity energy saved can be converted directly back into kilowatt hours delivered to the home (since electric heaters are virtually 100 per cent efficient), but natural gas energy must be augmented by two-thirds to capture the effect of saved conversion (in the furnace) and internal distribution losses. (The total efficiency of natural gas home heating in future was taken to be 60 per cent.) The value of natural gas saved is already reflected in the delivered price scenario.

The "Typical" New Non-Apartment House. The "typical" new house is a hybrid of five house types ranging from one-storey singles to row houses. Average attic, exterior wall, and basement wall areas were estimated for each of these types (using CMHC data[18]). This was then weighted by the proportion of total non-apartment starts to yield a composite house with 1,150 square feet (107 m²) of living space and a volume of 15,000 cubic feet (425 m³). See Appendix E, Table E.2, for more detail. Table E.11 contains the insulation installation costs assumed in this study.

Base Insulation Levels. In order to demonstrate the decreasing returns to insulation levels, two cases were considered. Case A assumes that all new dwellings are currently constructed to the mandated minimum standards contained in the Ontario Building Code (August 1978 revision). Case B corresponds to the insulation practices before the new standards were mandated. Table E.3 gives the details.

Energy Savings and Costs for a "Typical" House. Each table in the set E.4 to E.9 in Appendix E summarizes the optimal R values for one energy price scenario, assuming the insulation investment is undertaken in 1980 and at five-year intervals thereafter to 2000 with the expectation of a 30-year pay-back. The three price scenarios for gas are described in Appendix C. The three electricity scenarios selected were the medium average cost scenario and projections of the short- and long-run marginal costs to Ontario Hydro of meeting the space-heating load.[19] The energy savings and installation costs for additional insulation are calculated for base insulation Cases A and B. The combined vapour barrier/heat exchanger package, and the savings due to better design for passive solar gain, are included throughout. These two dominate the Case A results but are always less than half of the energy savings in Case B. Many interesting results emerge at this stage. Some observations:

1. The total insulation package, starting from the Ontario Building Code insulation levels and including the vapour barrier/air-to-air heat exchanger, would cost between $1,000 and $1,200, for a gas-heated house in 1980. For an electrically heated house, expenditures would range from $1,400 in the medium price scenario to $2,100 when the price equals the long-run marginal cost. The annual tertiary energy savings in the gas-heated house range from 29 to 31 million BTU, depending on the fuel price outlook, and would be worth about $200 per year in the early 1980s. (Table C.2 in Appendix C summarizes the delivered fuel price scenarios.) The electricity energy savings range from 33 to 37 million BTU per home, worth about $350 per year.

In all cases, if the investment were made in 1980, the discounted pay-back would occur in less than six or seven years. More substantial investments are justified by the year 2000, but, as they go hand in hand with higher fuel prices, the pay-back period remains about the same.

2. The Implications for insulation level of the cost difference between natural gas and electricity as heating fuels are well demonstrated by Case B. The total potential tertiary energy saving in a gas-heated house is higher than for an electrically heated home, yet the cost of the additional measures is lower. This happens, despite the fact that initial insulation levels are normally higher in an electrically heated home, because the premium price of electric energy makes substantially higher insulation levels cost-effective. The cost of saving each unit of energy is higher for electricity because of the decreasing returns to incremental insulation at high R values.

3. The difference between the energy savings from insulation in Case B and those from Case A represents the energy saved in moving from the estimate of insulation practice several years ago to the levels mandated in the Ontario Building Code. Depending on the price scenario, between 50 per cent and 75 per cent of the potential for conservation from improved insulation occurs by achieving the Building Code levels. The remainder, at higher R levels, is more expensive: the average cost of insulating from the Ontario Building Code levels up to the optimum is as much as four times the average from Case B level up to the level now mandated.

4. Only a small proportion of the additional energy savings achieved relative to Ontario Building Code standards is in the attic. Generally, upgrading the walls from R12 gives about half the savings and is closely followed by improvements to the basement. In Case B, the increase from R5 to R10 in the basement overshadows the enhanced insulation of both attic and exterior walls. The addition of about R10 to the basement walls, though a $500 project, gives high returns because of the low R value to begin with (see Figure E.1). This may be a significant retrofit opportunity in many houses.

Housing Starts in Ontario, 1980-2000. The housing start projection used to aggregate the potential savings for Ontario is consistent with a population of 10.3 million in Ontario in the year 2000. It was generated by CMHC's "Housing Requirements Model" and is known as "Projection 1", the low migration case outlined in their report of March 1978.[20] In this model, housing starts decline steadily from 85,000 units per year from 1980 to the mid 1990s, where they level off at 47,000 per year for a few years before picking up somewhat. This implies that about one-third of the 1.25 million units expected to be added to the year 2000 will be built by 1985. Any move towards required insulation standards or favourable financing of insulation will have to take place quickly in order not to miss a significant portion of the potential market.

This study deals only with non-apartment units, assumed to be two-thirds of the total starts. Of these,

three-quarters are expected to be gas-heated, and the rest electrically heated. The statistics are in Table E.10 in Appendix E.

Energy Savings and Capital Expenditures Associated with Space-Heating Conservation Measures. The estimate, presented here, of the aggregate potential for reducing heat loss in non-apartment dwellings to be built in Ontario over the next 20 years assumes that all new houses started in 1980 or subsequently will be optimally insulated. Given that public sector financing conditions are assumed, it is probably a maximum feasible estimate. Higher R values could be justified if the high-price scenarios prove not to be high enough, but, as has been emphasized throughout this section, further increases in insulation levels, beyond those cost-effective in the scenarios considered here, will yield diminishing levels of energy saving. Nonetheless, major changes in housing type (to emphasize passive solar features especially) or reductions in size would make an impact. While it would be prudent to plan with an extremely high-price scenario, overemphasizing insulation, just like overspending on nuclear power, could displace investments in other parts of the energy spectrum with a higher return.

The steady decline in housing starts imposes itself strongly on total energy savings. The estimates decrease in each five-year period from 1980 to 2000. Relative to Case B initial insulation levels, the maximum energy savings (including air infiltration control and passive solar gain) occur with a combination of the high natural gas price scenario and long-run marginal cost pricing of electricity. By the year 2000, tertiary energy saved is 47×10^{12} BTU, equivalent to 73×10^{12} BTU of secondary energy (taking into account the conversion efficiencies of the fuels saved weighted by the projected energy savings of each fuel). This is a reduction of about 50 per cent in home heating energy requirements in new non-apartment dwellings over what might have occurred with the Case B standards (see Table 5.10).

Table 5.10 Secondary Energy Savings from Measures to Reduce Residential Heat Loss

Price scenario	High gas		Long-run marginal cost electricity		Total	
	Case A	Case B	Case A	Case B	Case A	Case B
1980-84	10.7	19.5	2.6	3.6	13.3	23.1
1985-9	8.8	16.0	2.1	2.9	10.9	18.9
1990-94	7.3	12.7	1.7	2.3	9.0	15.0
1995-9	6.5	11.5	1.5	2.1	8.0	13.6
2000	1.3	2.3	0.3	0.4	1.6	2.7
Total	34.6	62.0	8.2	11.3	42.8	73.3

Note: Results for all scenarios appear in Appendix E, Tables E.13 and E.14.
Source: RCEPP.

The low gas price, medium electricity combination saves 44×10^{12} BTU, just 7 per cent less than the high gas price, high electricity pair. Tables E.12 and E.13 summarize potential tertiary energy savings and capital costs associated with each fuel price scenario and Cases A and B. Case A, consisting of insulation in addition to that mandated in the Ontario Building Code, the vapour barrier/air-to-air heat exchanger, and some passive solar gain features, results in tertiary energy savings of $25-27 \times 10^{12}$ BTU, or secondary energy savings of $39-43 \times 10^{12}$ BTU in the year 2000 (see Appendix E, Figure E.1 and Table 5.10).

The secondary energy savings may be put in perspective by noting that the projection of total secondary energy demand in Ontario in the year 2000 at a 2 per cent annual growth rate is about $3,400 \times 10^{12}$ BTU and residential sector demand may be about 600×10^{12} BTU.

The relative insensitivity of the aggregate results to the price scenario used to analyse the returns to investment reinforces the observation that action taken to encourage a long-run perspective to the home heating question may be a more effective force to motivate this form of conservation than price expectations by themselves. In addition, the uncertainty surrounding price movements may inhibit implementation. By some standards, the price scenarios used in this analysis might once have been considered high, assuming as they do that Canada prices oil in 1983 at the 1979 world price (estimated to be $18 per barrel). Events have overtaken them, and, by mid 1979 the scenarios as a group are probably on the low side.[21] (Note 21 estimates the additional insulation economically justified in new gas-heated houses should the world oil price reach $40 per barrel (1978 dollars) in the mid to late 1980s.) The scenarios could imply a gap between Canadian and world prices in 1983 similar to the gap that exists now. There will always be uncertainty about oil prices and about the price of fossil fuels whose

value is keyed to oil. When it is acknowledged that the price responsiveness of those making investments in home heating improvements is also not well understood, one may expect that relying purely on market forces could lead to a significant under-implementation of the optimum heat loss conservation package, even though it gives the province a higher rate of return than incremental generation capacity.

Lee Schipper made a similar point in a May 1979 article in the *American Economic Review*:

> Perhaps the most important reason for including key regulations in any policy is a fundamental lack of two other resources: time and certainty. We have made a political judgment that we must hurry to reduce our dependence on imports – dollar for dollar, barrel for barrel, conservation does this faster than new supplies. But both conservation and new supplies have uncertainties in practice. Building codes for example would act to minimize uncertainty over the pace and success of conservation in buildings and, as I have observed in Sweden and California, generally speed up the pace of technological change. Regulations on behaviour, on the other hand, whether in the form of maximum temperatures, gasless Sundays, bans on production of certain goods and services, or forms of energy rationing, have no place in any economic system accustomed to at least some degree of freedom of choice, and would hardly contribute to significant long-run energy savings.[22]

The highest estimate of the cumulative capital expenditures on this conservation programme, over and above the Ontario Building Code Standard, is $1.3 billion (1978 dollars) over the next 20 years (see Table 5.11 and, for other scenarios, Tables E.12 and E.13). Only a tiny proportion of this sum has a payback as long as 30 years. As noted earlier, as a package the additional insulation and air infiltration control installed to optimum feasible levels will average a pay-back of six or seven years at a 5 per cent real discount rate. The annual long-term financing requirements (Table 5.11) to implement the entire programme would decline from about $80 million (1978 dollars) in the early 1980s to about $10 million towards the end of the 1990s. *Retrofitting Attic Insulation.* Though other retrofit measures may be cost-effective on a large scale, the only one investigated here was the upgrading of attic insulation. Data compiled by Scanada Consultants Ltd.[23] and information from a survey by the Ministry of Energy, Mines and Resources "Enersave" programme suggest that the average value of insulation in existing attics is about R10 for oil- and gas-heated homes. Electrically heated homes are assumed to have R20. The retrofit standard was assumed to be what would be optimal for new houses in 1985 (see Appendix E, Table E.14). It was estimated that, currently, 43 per cent of Ontario's non-apartment dwellings are heated with oil, 49 per cent with gas, and 8 per cent with electricity (see Appendix E, Table E.15).

Table 5.11 Capital Expenditures on Additional Insulation and Air Infiltration Control (millions 1978$)

Price scenario	High gas		Long-run marginal cost electricity		Total	
	Case A	Case B	Case A	Case B	Case A	Case B
1980-84	250	390	140	170	390	560
1985-89	220	330	120	140	340	470
1990-94	180	270	100	110	280	380
1995-99	160	250	90	100	250	350
2000	30	50	20	20	50	70
Total	840	1,290	470	540	1,310	1,830

Source: RCEPP.

Table 5.12 Energy Savings and Costs Associated with Upgrading Insulation in Attics: Entire Ontario Residential Housing Stock[a]

Fuel scenario	Total number of attics retrofitted	Annual energy savings (10^{12} BTU)	Total additional cost (millions 1978$)
Gas (low)	1,158,336	12.9	401
Oil (low)	1,011,006	11.6	387
Electricity (low)	191,718	0.8	59
Total	2,361,060	25.3	847
Gas (high)	1,158,336	13.5	468
Oil (high)	1,011,006	12.1	446
Electricity (high)	191,718	0.8	70
Total	2,361,060	26.4	984

Note a) Non-apartments only. Insulation level assumes 7,500 degree days. See text for other assumptions.
Source: RCEPP.

Table 5.12 summarizes the results. Total annual tertiary energy savings from upgrading the entire non-apartment housing stock's attics would be about 26×10^{12} BTU. Equivalent secondary energy savings would be about 52×10^{12} BTU, assuming 50 per cent furnace conversion and distribution efficiency in the existing housing stock. The total bill comes to about $1.0 billion (1978 dollars).

The Unit Energy Cost of Measures to Reduce Residential Heat Loss

The unit energy cost for a supply project such as a pipeline, oil sands plant, or generating station is calculated by amortizing its capital expenditures over the assumed life of the project and dividing this annual capital charge by the expected average annual energy production. Priorities for capital expenditures in the energy sector are often determined by ranking projects by their unit energy cost. In practice, however, expenditures that reduce the demand for energy are rarely included in these comparisons.

The cost of saving a unit of energy may be derived in a similar manner: the amortized capital cost of the conservation measure is divided by the annual energy savings expected over the physical life of the investment. In contrast to the lump-sum nature of supply projects, conservation programmes tend to be made up of a large number of small energy-saving opportunities, some of which are more attractive economically than others. The measures discussed in this section do not have uniform characteristics, so that in order to aggregate them some simplifying assumptions were required.

The estimate of total capital expenditures is based on the universal implementation in new houses of the vapour barrier/heat exchanger package and of insulation up to the optimum R values justified by the price scenario assumed and a 30-year pay-back at a 5 per cent real discount rate. For convenience, the investments are assumed to be financed by a 30-year mortgage with a real interest rate of 4 per cent.

The feasible secondary energy savings potential in new homes (Case B) as a result of improved insulation and air infiltration control expenditures of $1.8 billion was estimated to be 73×10^{12} BTU per year. This works out to a unit energy cost of $1.43 per million BTU (1978 dollars). Starting with insulation levels equivalent to those mandated in the Ontario Building Code (Case A), $1.3 billion was required to save 43×10^{12} BTU per year – a unit energy cost of $1.75 per million BTU (1978 dollars). Upgrading from Case B insulation levels to Case A is estimated to cost $500 million and to save 30×10^{12} BTU, a unit energy cost of $0.96 per million BTU. The latter result emphasizes the high returns for initial improvements in insulation level. Nonetheless, even the Case A investments save energy at an average cost of about one-half that of the most attractive alternative supply options and about one-seventh that of new electric generating facilities operating at a 30 per cent annual capacity factor. It must be remembered, of course, that the estimated energy savings discussed here represent the accumulated savings over a period of 20 years as new housing is built and are probably close to the maximum feasible by the year 2000. They are not, by themselves, a large share of total energy demand likely in the year 2000. They may reduce total secondary energy demand in Ontario by less than 2 per cent in 2000 and residential sector energy demand by about 10 per cent.

The retrofit of attic insulation was estimated to cost $1 billion, and, mainly because about 90 per cent of the homes in Ontario are now heated relatively inefficiently with fossil fuels, it was expected to reduce secondary energy demand in the year 2000 by 52×10^{12} BTU – a unit energy cost of $1.11 per million BTU.

Residential Solar Space Heating and Water Heating

An analysis of the cost-effectiveness and likely market penetration of solar collectors used for residential space-heating and water-heating purposes is decidedly more difficult to perform than was the analysis of insulation in the preceding section. As in the other cases examined in this chapter, active solar systems are sensitive to the outlook for delivered fuel prices, financing arrangements, and government incentives. However, because solar heating is a relatively young technology, there remains considerable uncertainty about the performance and durability of solar equipment, how much to expect cost to come down as production volumes increase, and the part solar heating should play in the optimized configuration of a home-heating system.

To determine costs and the amount of energy delivered to the dwelling requires many more assumptions (or, failing this, scenarios) reflecting the engineering permutations of the technology than was necessary for either the co-generation analysis or the insulation analysis. A thorough analysis must

select the type of collector (flat plate, evacuated tube, etc.), the capacity of the storage system (short-term or annual), the optimal home heat conservation package (which may postpone the use of active solar or render it superfluous), the proportion of required heat to be supplied by the collector and the back-up fuel, and the combination of space heating and hot-water heating. To take into account all the technical and economic parameters would lead to an unmanageable number of scenarios for the purposes of a report such as this.

The RCEPP funded two studies of solar heating potential in Ontario. The first, written by the IBI Group and entitled "Solar Heating, An Estimate of Market Penetration", was published in 1977. It developed two scenarios, a "high-high" and a "low-low", to delineate a plausible range for market penetration and energy savings from solar. Each scenario polarized a combination of assumptions concerning fuel prices, government incentives, housing density, and interest rates, and was applied to diverse dwelling types with differing heating requirements.

The second study was in the form of notes prepared by Middleton Associates in 1979 as background information for this volume. It complements the IBI analysis by using the delivered fuel price scenarios presented earlier in this chapter, which fall between the extremes of the IBI study. The Middleton analysis selected an initial insulation level that results in home heat requirements of about half those of the IBI low conservation case, but still about twice those of the high conservation case. The life-cycle cost analysis employed a real discount rate of 4.5 per cent, roughly that used by Ontario Hydro, while IBI costed its systems on the basis of 1 per cent and 3.5 per cent real interest rates. Both assumed a 20-year physical life for the solar collector. Because of the high front-end costs of solar heating, neither study explored the market potential if a commercial rate of return on investment was required.

The IBI penetration rates were "guestimates" based upon the judgement of the study team bearing in mind the market shift behaviour among conventional heating energy sources over the last few decades".[24] They were applied after the technology became cost-effective. Middleton Associates used the Mitre-Metrek market share model, which permits some market penetration before the life-cycle cost of a technology equals that of the alternative. Also, the implication of a policy decision to implement all options cost-effective prior to the year 2000 was calculated. In general, the Middleton estimates of conventional energy savings from solar collectors fall at the low end of the IBI range of 1 per cent to 14 per cent of the residential heating demand in the year 2000.

Interestingly, the IBI study found that high levels of heat conservation were more important than the savings from the adoption of solar heating to the year 2000:

> In 2001 the estimated savings for heat conservation are 96.7×10^{12} BTU relative to savings of 70.9 $\times 10^{12}$ BTU from the high estimate of solar penetration [all markets]. That is, the savings from such additional heat conservation measures are about 35 per cent greater than those from the more optimistic estimates of solar energy adoption. By 2021 the estimated savings from solar energy use (high estimate) are much more significant, being almost 2.5 times the savings from the extra heat conservation measures. The importance of the heat conservation measures should be recognized and acted on, since they can take effect fairly quickly relative to the adoption of solar energy and they complement efforts to encourage solar heating. The later importance of solar energy should also be recognized since heat conservation can lower the rate of increase of conventional heating/energy consumption for only a few years, while solar (and other new energy forms as they become available) is absolutely necessary to decrease our longer-term dependence on fossil fuels for space and water heating.[25]

In a follow-up paper, IBI estimated the impact on peak Ontario Hydro capacity requirements of the displacement of expected electric space-heating and water-heating requirements by solar. Since a well-insulated and -sealed dwelling will not require peak-time electric energy as a back-up to solar in the middle of winter, even if only equipped with a short-term storage system, IBI concluded: "The peak capacity requirements would be reduced in the order of $0.2 - 3.6\%$ in 2001 and $0.8 - 4.6\%$ in 2021 if the off-peak use of electricity by short-term storage solar systems can be enforced."[26]

The IBI studies present a sobering appraisal of the prospects for solar heating in Ontario. This is consistent with our analysis undertaken in co-operation with Middleton Associates, which is predicated on the fuel scenarios that were applied to the other two alternative energy examples in this chapter. Let us turn to it now and begin with a review of the capital-cost assumptions that were made.

Middleton Associates considered that an evacuated tube solar collector showed the most promise for decreasing unit production costs over the years. It was selected for all solar systems analysed: combined

space plus hot-water systems in new single-family and multiple-family dwellings, and new and retrofitted hot-water systems. At an early stage of the study Middleton rejected retrofitted combined systems as too costly. Multiple-family dwellings were defined as having between 10 and 50 units, corresponding to roughly 30 per cent of total apartment starts. If it has more than 50 units, a high-rise apartment may have insufficient space to use solar collectors.

Middleton estimated the incremental cost (i.e., in addition to a conventional back-up heating system) of solar space heating and hot-water heating for a new single-family detached house to be $13,000 (1978 dollars), consisting of: the collector itself, $7,500; other equipment including storage and heat exchanger $2,500; and installation costs, $3,000 (1978 dollars). By the 1990s, the collector cost could be down to $3,250. A solar hot-water system on its own would cost about $2,500 for a new single-family dwelling and about 25 per cent more if retrofitted to an existing home. The unit cost of solar systems for multiple dwellings is roughly 65 per cent of the equivalent for single homes.

To be economic, the high front-end cost of solar must be offset by the value of the conventional energy savings over the 20-year physical life of the system, discounted at a suitable rate. In order to be able to compare the cost-effectiveness of solar with nuclear power on roughly the same basis, Ontario Hydro's real discount rate was used. The life-cycle cost analysis of each solar system relative to the price scenarios for conventional fuels at five-year intervals indicated that:

    1. No solar systems were cost-effective before the year 2000 using the high oil and gas and medium, average-cost, electricity price scenarios. When the short-run or long-run incremental electricity cost scenarios represented the cost of conventional fuel, some systems became cost-effective by the mid to late 1980s.

    2. Using the long-run incremental cost to Ontario Hydro of supplying electric space heating, both solar hot-water systems and combined space and hot-water systems are economic by 1985 in new multiple-family dwellings. After 1990, these systems appear to be extremely attractive. The life-cycle cost of electricity becomes nearly 50 per cent greater than the life-cycle cost of solar by the year 2000.

    3. By 1990, retrofitted hot-water systems in multiple-family dwellings and new hot-water systems in single-family dwellings become viable.

    4. In 1990, the ratio of the life-cycle cost of solar for space heating and water heating in single-family dwellings to the life-cycle cost of electric heating priced at its long-run incremental cost (about the end-use BTU equivalent of $40 (1978 dollars) per barrel of oil) is 0.92. By the year 2000, combined systems for single-family dwellings become nearly economic.

As already mentioned, the potential market for solar heating based on these life-cycle cost comparisons was estimated both by the Mitre-Metrek model and by assuming total implementation of cost-effective systems. The first approach uses market prices but allows for some implementation before cost-effectiveness is reached. This is the same phenomenon that accounts for continued installation of electric space heating when natural gas is available at lower prices. Perhaps it is explainable by life-style preferences or long-term security-of-supply considerations.

The conventional fuel alternatives that were selected as examples for implementation of solar were natural gas (high-price scenario) and electricity (medium-price scenario, the most likely market-price scenario without a change in rate structure). No oil case was needed as there is no retrofit solar space-heating potential. By the year 2000, the penetration model estimated that 43,500 new residential units in Ontario (36,000 of which are single-family dwellings) would have solar space-heating and water-heating systems. These units represent 3.4 per cent of the housing stock that is expected to be built between 1980 and 2000 and 1.1 per cent of the total housing stock in the year 2000. As many as 67,000 additional new and 120,000 retrofitted units may utilize solar hot-water heating by 2000. The model expects 90 per cent of the up-take of solar systems before 2000 to take place in the 1990s. The total tertiary energy saving if all systems were installed would be about 3.8×10^{12} BTU of which about one-third would be electricity. The capital cost would be about $700 million (1978 dollars). The unit cost of the tertiary energy saved is $13.6 per million BTU using a 4 per cent real mortgage interest rate. This corresponds to a natural gas price at the burner tip (customers' premises) of about $7 per million BTU (1978 dollars).

If the Ontario government wished to require the installation of solar collectors when they become cost-effective relative to the incremental cost of electricity, an additional expenditure of $260 million (1978 dollars) could be rationalized on top of the $700 million implied by the model. If only cost-effective systems were installed (as in paragraphs 2 and 3, above) an investment of about $300 million (1978

dollars) in solar before the year 2000 would be profitable, compared with supplying the same energy by means of electricity. As indicated in the insulation section, the fossil-fuel price scenarios may now appear to be on the low side. Going perhaps to the opposite extreme: if real natural gas prices rise to the point where they are equivalent to incremental electricity costs, then four times the capital expenditures on solar will become cost-effective before the year 2000. This maximum self-sufficiency scenario could cost $1.2 billion (1978 dollars) between the late 1980s and 2000.

The implementation of solar heating suffers more than the insulation programme from the projected decline in housing starts in Ontario because, by the time it becomes economically attractive, about half the new housing units to be built in 1980-2000 will be completed. Solar penetration could be increased by encouraging more multiple housing units of the appropriate design than the analysis assumed (i.e., increasing the proportion of apartments but ensuring that sufficient collector area is available) so that solar may be utilized in more than 30 per cent of new apartments.

The incentive to install solar systems would be enhanced by charging prospective electric space-heating customers electricity rates that reflect the long-run incremental costs of providing electricity for the winter months. This could be implemented by a seasonal tariff structure in which the tail block rate (e.g., over 750 kW·h per month) is made equal to the long-run incremental bulk power costs of meeting the space-heating load plus an incremental delivery or distribution charge.

Solar heating is a particularly good example of a capital-intensive alternative energy source whose front-end cost presents a serious obstacle to its widespread implementation. This analysis has not incorporated any measures that help to reduce its initial cost or financing charges; in other words, solar costs were evaluated under an approximation of current market conditions. It was beyond the scope of this study to estimate the impact of plausible government policies to assist the purchasers of solar systems.

In Canada to date, government initiatives to reduce the capital cost of solar systems have focused on improving the design of the equipment sold in Canada and increasing the production runs of domestic firms. To this end, the federal government provides funds for research and development programmes and purchases solar equipment for government buildings. Eventually, to promote the market penetration of solar, the emphasis on the supply side will need to be complemented by efforts to stimulate consumer demand.

The economic attractiveness of solar can readily be enhanced by conventional fuel pricing policy, as noted briefly above and elsewhere in the report. Apart from the appropriate decisions in this area, government has various means at its disposal to assist the market penetration of solar at the time the purchase is made or over the life of the solar equipment. Traditional tax incentives, such as an income tax credit on the initial cost, an income tax deduction for depreciation of the equipment, and exemption from sales and property taxes, would reduce the effective front-end cost. Direct grants or subsidies would also achieve the same purpose. Over the longer term, the carrying charges for solar equipment may be made more affordable by making low interest loans available, subsidizing commercial bank mortgages, or allowing mortgage interest for solar equipment to be tax-deductible.

These measures are not innovative, except perhaps in their application to conservation and renewable energy in Canada. The U.S. has already enacted state or federal legislation to encourage solar energy (and the other alternatives discussed in this chapter) with incentives along the lines described above. A synopsis of U.S. legislation to promote solar energy is provided in Appendix F. It will be several years before the success of the U.S. programme can be evaluated. California has developed its own goal of 1.5 million solar homes by 1985. An assistant to the Governor explained the state's high tax credits for solar to the U.S. Congressional Subcommittee on Energy:

> So we find ourselves in a unique position: To get solar energy in use now, we will have to remove the subsidies from other fuels, or provide, as we have in the State of California, a very special subsidy for solar for a period of time. Because as we look out over a 10-year period, we see very expensive energy sources, and we see a competitive market for solar. But today, when we have cheap subsidized fuel from centralized sources, and when the consumer is really not paying the full costs of that fuel, solar can't compete. That is why you need the credit.[27]

Conclusions

Our analysis of co-generation found that a business would prefer to install gas rather than coal-fired co-generation in the 1980s because the lower front-end costs offset higher fuel costs. Later on, natural gas prices are expected to increase in comparison with coal prices, and this will likely swing the balance the other way. If Canada has a surplus of natural gas (or residual fuel) but must import thermal coal, gas-fired co-generation could be a thermodynamically efficient addition to the domestic natural gas market. Nonetheless, with financing and coal-purchasing conditions equivalent to Ontario Hydro's, coal-fired co-generation will remain cost-effective relative to nuclear power for some time to come. The potential for retrofitted and new co-generation ventures could be about 2,300 MW in Ontario to the turn of the century at a cost of $1.3 to $2.6 billion (1978 dollars).

The section on the potential for higher insulation levels and improved air infiltration control in new non-apartment dwellings developed a package of $1.3 to $1.8 billion (1978 dollars) of cost-effective investments that could be made over the next 20 years. It is also estimated that $1 billion could be well spent on attic insulation retrofits in Ontario.

Both electrically and non-electrically heated homes were included in these totals. It was felt that where extremely cost-effective measures to reduce home heat loss are available they should be undertaken prior to attempting to promote electricity to displace fossil fuels for home heating. There would be a waste of resources if generating capacity were installed to meet a home-heating load that had not been pared down by conservation measures to the fullest extent justifiable by a life-cycle cost analysis that used the same discount rate and time horizon as the generation investments. The results indicate that no such reduction in residential heat loss is likely to be achieved through the action of market forces.

The province may be better served by the development of standards for the new housing stock in Ontario that are consistent with the government cost of capital and a 30-year pay-back. It would be appropriate to use the long-run marginal cost of electricity to supply this low load factor end use as the price scenario in determining the standard for electrically heated homes and possibly even for natural-gas-heated homes. Nuclear power used to serve a 30 per cent annual load factor customer is competitive with natural gas for home heating when gas is priced at a 100 per cent BTU equivalence with oil at $40 per barrel (1978 dollars). The additional costs of retrofitting later may warrant what appears now to be premature upgrading of the entire new housing stock. These measures would boost the cost of new housing to buyers. The increment in cost could be mortgaged separately and guaranteed by the province and could be paid off in such a manner as to reduce the drain on family income that would otherwise result from a higher fuel bill.

Solar space-heating and water-heating systems have such steep front-end costs that they become economically attractive only when life-cycle costing is performed using low discount rates and high conventional fuel price scenarios. Discounted at Ontario Hydro's real rate of 4.5 per cent, roughly double the 1978 real home heating fuel price is required before combined space-heating and water-heating systems in new multiple-family dwellings become cost-effective. These two conditions also render solar water heating viable on its own in new single- and multiple-family dwellings and retrofitted in existing multiples. However, that price increase does not appear to be sufficient to justify combined space and hot-water systems in new or existing single-family dwellings or in existing multiple-family dwellings.

Of the fuel price scenarios used in this study, only the incremental cost of electric space heating escalates rapidly enough to make solar competitive before the year 2000. By the time it becomes cost-effective relative to electricity in the late 1980s, half the new houses projected for 1980-2000 will have been built, further complicating its implementation.

The material prepared for this volume leads to an estimate of conventional energy savings due to active solar systems in the year 2000 that is at the low end of the range found by the IBI Group, in their study prepared for the RCEPP in 1977.[28] IBI estimated that between 1 per cent and 14 per cent of residential heating demand might be met by solar at the turn of the century. If residential systems are installed only as they become cost-effective relative to incremental electric space-heating costs, then cumulative capital expenditures on solar in Ontario by 2000 may be limited to $300 million (1978 dollars). If residential market penetration occurs before solar heating becomes justified on strictly economic grounds, expenditures of $700 million (1978 dollars) are projected by the Mitre-Metrek model. In a maximum self-sufficiency scenario, or in one where all real fuel costs double by the year 2000, there is a

cumulative potential for a $1.2 billion (1978 dollars) capital expenditure programme in Ontario before the turn of the century.

The types of incentives given to install solar equipment in the U.S. that are summarized in Appendix F may also be applied to help overcome the financial obstacles facing many decentralized front-end-loaded energy expenditures. The intent of such tax incentives is to harness market forces to achieve national/regional goals. This approach does not interfere with the market so much as improve its information flow and attempt to adjust inconsistencies in regulated prices. It becomes clear, however, that the starting point in any energy sector investment is some understanding of the degree of self-sufficiency or security of supply that is desired over the long term. As more demanding energy goals are set, the time horizon for a return on energy investments lengthens and the willingness to provide incentives for them increases.

There is no "best" approach to encouraging the implementation of conservation and renewable energy programmes. Nonetheless, if the province wishes to extend its planning horizon for alternative energy forms as far as Ontario Hydro does, it must accept a greater degree of government involvement in motivating investments. The examples discussed in this chapter have illustrated the diversity of approaches that are open. In order to promote industrial co-generation, a mini-utility backed with provincial debt capital may be needed to lead to maximum economic market penetration. Heat loss or building design standards will probably be needed to optimize home heat conservation measures. Solar heating may require tax credits or low-cost financing before it makes a significant dent in the residential heating market.

Many expensive energy-sector investments remain to be evaluated, such as the massive infrastructural changes required to improve energy efficiency in the transportation sector. However, industrial co-generation, home heat conservation, and solar space heating and water heating represent in our view three of the most important opportunities for improving the efficiency of energy use in Ontario. Each could reduce the need for centrally generated electric power and is, or will shortly be, cost-effective based on economic decision criteria used by Ontario Hydro. The programmes described involve spending between $4 and $7.6 billion (1978 dollars) over the next 20 years. Depending on the method of implementation, financial assistance from the province in the form of allocations of long-term debt would probably be needed for less than half of the total spent by individuals and firms. The burden on the capital resources available to the province should be acceptable, given that it would be less than the $6 billion (1978 dollars) reduction in Ontario Hydro's capital expenditure programme for 1979-94 that occurred as a result of the downward revision of the load forecast between 1978 and 1979.

The Employment Impact of Energy-Sector Capital Expenditures

Traditionally, North American society has viewed increased real income and leisure time as the goal of economic activity. High productivity growth is, almost by definition, the mechanism that achieves both simultaneously. The increasing of output per person, with the aid of capital goods (made by somebody else), remains a fairly benign force as long as leisure time is shared evenly amongst those wishing to participate in the labour force. However, if income earning capability becomes concentrated in one group while another is relegated to total unemployment, the resulting disparity creates a social problem that may be solvable only by a redistribution of income in one form or other. As the redistribution of income by government involves a distortion of the incentive structure that motivates individuals (e.g., it may require higher income taxes), a free enterprise system would prefer to distribute income directly through the jobs individuals hold. Society is, therefore, obliged to look for a way to increase the number of jobs as an end in itself. This objective may not be consistent with increasing either aggregate income or leisure time.

One approach to providing more jobs is to distribute the available work more evenly by shortening work weeks, increasing holidays, providing frequent retraining, or adopting any other measure that increases the flow of individuals through an income-generating activity. This may evolve eventually, but it can be expected to be a slow process. Another approach, advocated by many groups including conservationists, is to encourage the growth of labour-intensive sectors of the economy. If a labour-intensive investment programme makes the economy more efficient at the same time, it is a very desirable solution to the unemployment problem.

Numerous studies published in the U.S. and Canada assert that expenditures on conservation or renewable energy create more person-years of employment than the same expenditures on new supply sources. The number of jobs is not the only factor; their location and the skill level of the jobs relative to that of unemployed workers, and the small scale of the businesses offering the work (which localizes the spending of the income) all seem to favour conservation activities. (Conservation and renewable energy are lumped together in this chapter.) Groups in the U.S. such as the Environmentalists for Full Employment, the Council on Economic Priorities, and Friends of the Earth, and in Canada organizations such as Energy Probe, suggest that the best way for society to solve the pending energy problem and reduce unemployment concomitantly is to pursue a "soft" energy path.

Backing up these propositions is difficult and has as yet not been handled rigorously enough to permit comparisons of the impact of capital expenditure programmes for supply projects and conservation to be made on an equal footing. Studies differ in terms of the formulation of the energy problem to be solved (i.e., the energy end use, the basis on which cost-effectiveness is determined) and the boundaries (geographic, temporal, and cross-sectional) to be placed on the impact analysis. Qualitative conclusions may be reached in some clear-cut instances and particular value judgements may determine other trade-offs. In general, however, quantitative methods now available are limited in their ability to answer the questions being asked of them. Undoubtedly, clarifying the issue is the first step. Let us start by introducing the terminology and reviewing the methodology used in comparisons of the employment impact of capital expenditure programmes. We will then proceed to examine the proposition that capital expenditures on conservation are more labour-intensive than similar expenditures on conventional energy supply sources.

Terminology used for Employment in the Energy Sector

Employment is usually measured in terms of the number of people working for a specific period of time. Person-years of work, the most common unit, may only be converted into "permanent" jobs if one-time capital expenditures are of sufficiently long duration, or are repeated regularly enough, to sustain a stable work force.

To begin with, we will be referring primarily to the employment impact of the capital expenditure programme during the construction phase. Operation and maintenance employment will be introduced later. The capital-intensity of almost all energy-sector projects is extremely high so that few energy projects are attractive, in their own right, for long-term job creation. From this perspective,

they should only be undertaken because they help in the solution of the long-term energy supply problem.

Three categories of employment impact are generally referred to, though their definitions vary from study to study. The following is a reasonable consensus. Direct employment occurs on-site, in construction, but also includes those people involved in the design phase. Indirect employment refers to the person-years of work in the industries that supply components for the energy project, as well as all the work entailed within the geographical region of interest in the fabricating of those components. Induced employment is employment created by the demand arising from the respending of the income earned in both direct and indirect employment – i.e., when construction workers or solar panel makers spend their pay cheques on goods and services.

Quantitative Methodology

The tools available to economists for analysing the impact of alternative investments, the input-output (I-O), and the macro-economic model, reflect the static or comparative static economic theory on which they were developed and the data problems inherent in applied work. The complexity of these models surrounds the results with a mystique of sophistication and enables an expert to "prove" almost any proposition to the uninitiated, who may not realize that most of the relevant inputs represented judgements on the part of the modeller and not the objective calculations of the model. This comment is not meant to denigrate the rigour that comes with quantification and explicit logical structures, but merely to acknowledge that there remains a critical judgemental component in the results produced by the current generation of economic models.

Direct and indirect employment effects are calculated by an I-O model with an added matrix that converts the average output produced by an industry into average person-years of work by dividing it by the average wage in the industry (suitably corrected for productivity gains). For the purpose of comparing specific energy investment programmes (e.g., nuclear-generated electricity, insulation upgrading, solar hot-water heating) at the provincial level, this methodology has serious limitations.

All I-O models in Canada are derived from detailed Statistics Canada input-output tables of the national economy. At the national level, care must be taken in describing the indirect effects of an investment, as determined by an I-O model, since the treatment of the foreign sector by the model user may have a major impact on the final results. Models that purport to give provincial employment impact results can be considered only highly approximate as there is, so far, no data base available with which to estimate interprovincial trade balances and, thus, to determine how much activity remains in the province. In provincial models, developed despite the data problem, industrial categories have been aggregated to the point where the industrial mix of most energy sector projects would appear very similar. A further cautionary note is that the averaging used in the calculation of employment effects implies that employment is proportional to output. The real-world impact of individual energy investments could be larger or smaller than that indicated by the model, depending on the rate of capacity utilization in the firms supplying an order.

The employment induced by the additional demand for goods and services that is caused by the increase in the income of the energy sector is estimated by means of the multipliers of a macro-economic model or a generalized consumer expenditure run through the I-O model. Normally, it is assumed that induced effects are sufficiently similar for all energy projects that they will cancel out in a comparison of two standardized alternatives. This assumes, as an economic model does in the present state of the art, that individuals at different income levels spend similar portions of their income on things that have similar provincial content. If two projects make the same payments to labour but differ significantly in terms of the average wage of the jobs created, one would expect the project paying lower wages to a larger number of employees to stimulate higher induced employment in the province. Nonetheless, because this effect has not been quantified, the employment impact measure that is generally used for energy project comparisons is the sum of the direct and indirect person-years of employment associated with the incremental investment.

Maximizing Economy-Wide Employment through the Selection of Energy-Sector Investment Programmes

The direct and indirect employment that an energy project creates represents a clear net gain to total employment only if no other energy- or non-energy-sector investment appears feasible at the time.

Otherwise, the employment gain to the economy by investing in one energy project or another is the difference between the two total (direct and indirect) employment impacts plus a correction factor, which may be quite large, for the cost-effectiveness of the energy project chosen. The latter is needed because comparisons within the energy sector do not take into account the impact on the rest of the economy of the diversion of resources away from other productive uses.

Overinvestment in the energy sector is possible when the long-term potential to increase real per capita income would be better served by increasing net export sales of goods and services than by reducing net energy imports. It is most likely to occur when economic efficiency criteria are overridden by other societal objectives such as security of supply or the maximizing of short-term employment. When the latter leads to energy-sector projects not being undertaken in order of decreasing unit energy cost, that is, when less cost-effective energy options are preferred for their short-term job-creating ability, output outside the energy sector falls (if not during installation, then later on in the project's life cycle). This, incidentally, puts a high priority on uniform assessment of the cost-effectiveness of all energy options.

When the payments for energy services required to meet perceived needs are reduced by the choice of cost-effective energy systems, the extra consumer or corporate spending made possible outside the energy sector stimulates the production of other goods and services. In the process, it creates employment opportunities above and beyond those connected with the net gain or loss from the energy capital expenditures programme.

For example, sub-optimal insulation in buildings will lead to unnecessary increases in heating bills, reducing the disposable income that could be spent on non-energy purchases. The opposite case could arise, if, for instance, solar heating was not cost-effective relative to other fuels or conservation measures when all were assessed on an equivalent basis. Overinvestment in solar may create more employment to begin with, but payments for heating for the next 20 years or so would be higher than they need be, depressing local employment prospects later on.

These two examples demonstrate the weakness of two statistics that are commonly used to standardize the employment impact of capital expenditures on energy: jobs created per billion constant dollars expended and jobs created per quadrillion of end-use British Thermal Units supplied over a life cycle. Even when the definition of jobs is consistent between studies, both statistics can be misleading because they do not take uniformly into account the cost-effectiveness of energy investments to meet a specific end use. The first statistic allows comparisons of investments, such as home insulation, with energy systems supplying totally unrelated end uses that may not be amenable to such simple solutions. The second statistic could appear attractive from the perspective of employment in the energy sector only because much more was spent than was necessary to achieve the desired objective.

The employment gains due to the cost-effectiveness of conservation investments relative to conventional supply systems may, in fact, be quite significant in comparison with the more direct employment impacts. A study commissioned by the U.S. Congressional Subcommittee on Energy entitled the "Employment Impact of the Solar Transition" (by L.S. Rodberg, April 1979) presented a snapshot approximation of this component of employment impact analysis. For the year 1990, it compared a base-case projection of U.S. energy consumption with an alternative scenario in which it postulated "that investment in conservation and solar energy builds up over a 5-year period preceding 1985, with a constant level of investment thereafter".[1] The level of investment in conservation and solar measures each year after 1985 is $66 billion (1978 dollars). In 1990, the study found, this level of investment would create direct and indirect employment of 2,170,000 persons in the U.S. It concluded:

> The introduction of these measures [i.e., the 10-year program] leads to very significant savings of non-renewable fuels, reducing their consumption by 44.9 quads in 1990.... These savings allow projected spending on non-renewable fuels to be reduced by $118.8 billion in 1990, leading to 1,137,-000 fewer jobs in the fuel-producing and electricity-generating industries. If these dollar savings are spent on other goods and services, an additional 1,870,000 jobs will be created in other industries. In net, 2,903,000 jobs will be created in this scenario, as compared to the "business as usual" projection.[2]

These results indicate that of the total 2.9 million additional jobs in 1990, about 1.0 million would be a net gain to the energy sector (i.e., 2.1 million added jobs in conservation and renewable energy and 1.1 million fewer jobs in fuel-producing and electricity-generating industries) and 1.9 million would be created in other industries due to the increased spending made possible by the accumulated savings from reduced fuel consumption. The study estimated that of the 1.1 million jobs lost in the energy

sector, 0.5 million were associated with a $16 billion reduction in capital expenditures on new electricity-generating capacity. Per dollar expended, the estimated number of jobs lost by building fewer generating stations is about equal to the number of jobs gained as a result of the conservation and renewable energy programme. Without putting too much weight on the precise numerical results, the methodology employed in the Rodberg study suggests that the major source of new employment, arising out of a CARE programme whose expenditures equalled those for electricity-generating capacity, would be the jobs created by the additional spending permitted by its lower unit energy costs.

Economists have acquired a reputation for claiming that "if the total indirect and induced jobs are taken into account, then the result of investing a sum of money in plant is that eventually the same total number of direct, indirect and induced jobs will be produced, regardless of the industry sectors or technology in which investments are made".[3] To be meaningful in a macro-economic context, the statement must be qualified, at least by referring to relatively cost-effective investments and taking into account the effect of several distributional factors (discussed below). When properly qualified, it does not support the implication drawn in the study by the Centre for Alternative Industrial and Technological Systems (quoted above) that "the more expensive nuclear programme should ultimately generate more jobs".[4] On the contrary, as long as alternative energy solutions are cost-effective, ultimately more jobs will be created by the less expensive programme, following the reasoning developed above.

This chapter began with the observation that employment creation is a concern because it is through work that economies prefer to distribute income. Thus far, distributional factors have not been introduced. Considerations of economic efficiency and scale of investment have been shown to be major determinants of the magnitude of the employment impact of energy-sector expenditures. However, even though the debate about jobs and energy has raged over the numbers of jobs, it is probably because of job distribution that conservation and the renewables may be deemed to be labour-intensive.

When an analysis concludes that one investment programme has the same employment effect as another, many questions are left unanswered. It is still relevant to inquire whether these jobs will occur now or in the future, whether they are located in Ontario or somewhere else, whether they are highly skilled and well paid or not, and whether they displace or augment existing jobs. These are probably the issues that distinguish energy solutions and could reorder the priority with which projects are undertaken.

The Distribution of Employment

Jobs Now versus Jobs Later

Relative to supply systems, in general, and electricity utilities, in particular, conservation measures and renewable energy sources require few ongoing operations and maintenance personnel. Employment impact studies rarely credit any job creation after installation is complete to conservation investments, so that total person-years of work created is the sum of numerous, one-time, small-scale projects. Consequently, at some point in the analysis of the employment impact, a comparison of a conservation programme with, for example, the construction and operation of a nuclear plant will involve a trade-off between jobs in the short term and jobs spread out over the life of the reactor.

In a study for the Economic Council of Canada, D.B. Brooks estimated the direct and indirect employment impact of additional insulation in new and existing houses. In the case of retrofitted insulation, where no new supply facilities were displaced by the energy savings, Brooks concluded:

> So far as labour is concerned, direct ratios are difficult to put forward inasmuch as gains occur once while the losses are annual.... Something over 44,000 man-years of employment were created in making and installing the insulation whereas only 800 man-years of employment were lost each year because of reduced energy output and up to 8,500 man-years might be lost (on a one-time basis) through elimination of the need to build replacement production capacity.[5]

Without questioning the validity of the estimates themselves, they imply that if the dwelling is still standing 45 years later, the jobs gained will break even with the jobs lost. One is put in the ironic position of considering whether to discount jobs lost to the present in order to be able to compare person-years now with person-years later. The position is ironic because the cost-effectiveness of most conservation measures rests on long life cycles with minimum discounting.

When new supply systems are displaced in Brooks's study, the net gain from higher insulation standards in new homes narrows considerably and would become negative if ongoing employment were included.[6] Had the study estimated the employment-stimulating effect of the non-energy consumption made possible by implementing these cost-effective measures, it would probably have been able to demonstrate a clear employment advantage for higher insulation levels. As Brooks noted: "There is hardly any way that one can spend money that will not be significantly more labour-intensive than spending on energy itself."[7]

The one-time nature of jobs that involve installing conservation measures reflects their capital-intensity. The concentration of the employment impact during the installation phase is desirable for economic stabilization policies but could backfire later on if overinvestment dampens demand outside the energy sector. In most cases, the timing of the employment impact would be unlikely to alter the choice between conservation and conventional fuel supply that would be made on the grounds of cost-effectiveness alone. A preference for "once through" over "annual" person-years only highlights the contradictory goals of increasing long-term economic efficiency and employment at the same time.

Jobs in Ontario versus Jobs Elsewhere

Estimates of the person-years of employment created by a capital expenditure in the energy sector are conditional on the geographical area for which the employment impact is measured.

Studies done for an entire country, such as Canada or the U.S., will entail trade-offs in energy-sector employment opportunities that may not arise at the provincial level because the energy alternatives do not exist locally. Unbalanced internal financial flows within the same country could mean that one region loses out when it purchases energy, or capital goods to produce or save energy, from another region, an effect that is not apparent at the national level. Each aspect of the employment impact (direct, indirect, and induced) is sensitive to the provincial content of the energy alternative adopted. Because regional characteristics affect the employment impact so significantly, studies undertaken for other jurisdictions may be indicative for Ontario but must be interpreted cautiously.

Expenditures on the design and installation stage of energy systems are almost all for services that normally have a 100 per cent local content. Clearly, the importing of energy transfers the direct employment outside the province to the fuel-producing regions. The employment penalty could be offset, should there be extra cost-effective investment opportunities that may be exploited to offset the energy imports.

Because of the high Ontario content of this stage of a programme of capital expenditure on energy, it does matter what proportion design and construction represents of the total expenditures. The Ontario content of the components to be installed is not likely to match the Ontario content of the design and installation phase, though it may be higher than the manufacturing-sector average. As a result, an expenditure that has a higher ratio of design and installation to manufacturing costs will likely create higher provincial employment. The sense in which decentralized energy systems are labour-intensive is probably that their ratio of direct to indirect employment is higher than for equivalent expenditures on centralized systems.

Minimizing the "financial leakages" from the province has its greatest impact on induced employment. As the induced employment effect is defined to be the employment created when goods and services are purchased by income earned in the energy sector, the size of the induced effect depends directly on the Ontario content of the entire expenditure. Two other factors are also noteworthy. As indicated earlier, the propensity of individual consumers to import goods and services from outside the province may vary with their income level. Also, the proportion of corporate income spent in Ontario will vary with the size of the company. A multinational may be expected to transfer more of its earnings outside the province than a small firm.

The pitfalls in indiscriminately applying the results of an analysis of another part of North America to Ontario may be illustrated by the following example from a forthcoming study of residential conservation and solar space and water heating for Long Island by the Council on Economic Priorities (CEP). Early drafts were discussed in an article entitled "Nuclear, Solar and Jobs" (*Solar Age*, August 1978) and before the U.S. Congressional Subcommittee on Energy (March 1978).[8] The study examines the employment benefits for Long Island of upgrading its entire housing stock by installing higher levels of insulation and implementing other measures that would reduce home heat loss, and by adding solar panels for space heating and water heating instead of building two new 1,150 MW nuclear units to

perform the same task. The CEP study obtained results similar to those presented in Chapter 5, namely, that the residential conservation measures were decidedly cost-effective while unit energy costs from solar were equivalent to electricity costs for space heating from nuclear stations. The study's measure of employment impact was direct employment plus indirect employment restricted to that which occurs in the supply industries. The study found that the employment created on Long Island would be about 2.5 times greater with the conservation/solar option.

This result may be explained almost entirely by observing that, apart from the jobs on the site of the nuclear station, only 20 per cent of the national indirect employment opportunities in the nuclear industry would be situated in Long Island. As Long Island has a very small indigenous nuclear industry, it is clearly in the interest of its labour force not to build nuclear plants, if it has a cost-effective alternative. The employment argument in favour of the conservation option, as made using the CEP approach, is conditional on regional industrial characteristics. If the trade-off for Ontario were the same as for Long Island, the fact that the Ontario content of CANDU reactors is so high could even out the employment effects. Nevertheless, in the case of Ontario, other characteristics of its situation would suggest that a stricter matching of energy options to end-use demand might not indicate nuclear power as the alternative for residential space heating for some time to come (see Appendix A and Chapter 5).

The residential space-heating and water-heating market in Ontario may still be met largely by imported fossil fuels for the next 20 years or more. In this context, the employment impact in Ontario of investments that reduce the demand for coal-fired electricity, oil, and natural gas is relatively clear-cut. If, to choose a straightforward example, insulation were installed up to the optimum R level, as discussed in Chapter 5, Ontario would retain nearly 100 per cent of the direct and indirect employment in fabrication and installation. The induced employment would also occur primarily in Ontario. These employment gains would be augmented by the spending by individuals and firms of the savings in fuel costs that result from the insulation programme. This effect could be greater than the stimulus the Ontario economy receives from the recycling of petro-dollars paid to the producing region. Ontario would thus avoid some of the transfer of "economic rent" to western Canada that does not return to it in the form of purchases of goods and services made in Ontario.

If nuclear-generated electricity becomes a cost-effective substitute for fossil fuels, outside the end uses traditionally served by base-load electricity, then conservation and nuclear will become competitors. At this point the energy supply and employment problems will probably merge. Ontario will have to choose the optimal combination of nuclear-generated electricity and conservation expenditures that will minimize the transfer of income from the province without unduly reducing the future consumption possibilities of Ontarians in the process.

Jobs in Established Industries versus Jobs in New Industries — Transition Problems

The Canadian and U.S. studies that show the employment gains from capital expenditures on conservation relative to conventional fuels in the most favourable light have restricted their analysis to direct employment effects. However, spending on conservation may also be expected to displace a considerable number of indirect jobs in the industries supplying component parts and fuels for the conventional energy sector, as is demonstrated in the Rodberg report, quoted above.

Brooks's study for the Economic Council of Canada (ECC) estimated the net gain in direct and indirect employment as a result of improved levels of insulation. It estimated job losses in the oil, natural gas, and electricity supply industries and weighted each by its current share of the national house-heating market. As the decremental employment effects for oil and gas were calculated to be minimal, electricity, with 6 per cent of the national market, made up 25 per cent of the one-time labour losses. P.A. Victor's study, "Solar Heating and Employment",[9] assumed that jobs lost due to increased solar penetration would only be those directly associated with the domestic refining and distribution of imported crude oil. Both studies were set in a Canada-wide energy framework.

From Ontario's perspective, most of the job loss due to increased conservation of fossil fuels (including coal used for electric power generation) would take place outside the province. Should reduced demand for electricity cause deferrals in orders for CANDU reactors, jobs in the province's nuclear industry could be threatened. However, only if the expansion of nuclear generating capacity were seen as an efficient way to substitute indigenous energy for imported fossil fuels would conservation programmes

square off directly against the nuclear industry. In spite of the local nuclear industry, Ontario clearly has more to gain by conservation in employment terms than Canada as a whole.

Actually reaping the employment gains will be much more difficult than might be inferred from the Canadian studies cited above. Job losses in established industries can be effectively resisted even if there are greater net employment opportunities in new and expanding industries. It will be some time before the potential beneficiaries of a drift towards a conserver society will be able to make their case with the same force as long-standing industry lobbies and organized labour, which may lose by a change in the status quo.

The returnable-bottle case illustrates the dilemma well. The labour union whose high-wage jobs in the manufacturing of cans were at stake faced no opposition from the potential bottle recyclers who might have outnumbered them three to one.

In helping the province to take advantage of measures to improve the efficiency with which conventional energy is utilized, government will have to tackle numerous transition problems. Emphasis will have to be given to manpower information and training programmes that can help ease the inter-industry shift that such an adjustment entails.

Conclusions

The employment impact of energy-sector capital expenditure has become a controversial dimension of the debate surrounding the selection of an energy strategy. This chapter has attempted to demonstrate the complexity of calculating the total economy-wide employment created by an energy project during its installation phase and throughout its physical life. The current generation of economic models probably cannot differentiate the employment impact (particularly at the provincial level) of energy supply and conservation/renewable energy investments when equal expenditures are made with roughly comparable regional content. Any preference for one or the other method of serving the same end use arises chiefly from differences in cost-effectiveness, as determined by an evaluation of the alternatives made using common assumptions. Undertaking, as a top priority, those energy-sector investments that either supply or conserve energy at the lowest unit cost will allow the energy consumer to spend his fuel savings (relative to the available alternatives) on other goods and services. These expenditures should result in the creation of more employment than equivalent expenditures on energy itself.

When two investment opportunities providing energy of equal unit cost differ in Ontario content, the investment with greater Ontario content will most likely have the greater impact on employment in the province. If nuclear power and conservation/renewables become competitors in serving the same end use (e.g., space heating), this will probably not make much difference to the estimate of jobs created, because the Ontario content of each is so high. The distribution of jobs over time and any transitional problems that arise between existing and new industries will likely be more critical considerations.

The approach taken here places great weight on traditional economic efficiency criteria. In doing so, it cannot be overemphasized, comparisons of energy-sector alternatives must be made on a uniform basis in order for the ranking of investments that emerges to reflect the preferred allocation of resources from an overall employment perspective. The previous chapter indicates that there is considerable potential for alternative energy investments that would be cost-effective in comparison with nuclear power in their respective end uses. More comprehensive work analysing the unit cost of Ontario's conservation and renewables options may be more valuable than partial analyses of the impact they would have on employment.

An Estimate of the Incremental Costs of Expanding the Total Electric Power System

Introduction

In comparisons of generation from coal-fired and nuclear stations, many system costs that apply whichever form of generation is chosen are excluded from the cost-benefit study. These costs include the additional capacity required as back-up to preserve reliability, capital expenditures on transmission and distribution, line loss in transmission and distribution, and the operation, maintenance, and administration of the non-generation portion of the system.[1] For the purpose of comparing other investments in the energy sector with the supply of electricity from centralized generating stations, it is important that these additional costs be included in the estimate of the delivered cost of electricity. As the load factor of the end use being supplied will have an impact on the unit cost of electricity, a comparison of electricity costs with other energy alternatives should specify the end use. This appendix derives estimates of incremental system costs to serve a 30 per cent annual-load-factor (ALF) use such as space heating, and a 65 per cent and 100 per cent load-factor industrial customer. The reader will find the detailed assumptions used to derive the results at the end of this appendix.

The emphasis on the annual load factor of the end use was intended to demonstrate the variability of the unit cost of electricity generated by a nuclear station. A common practice in comparing nuclear power costs with other energy alternatives has been to evaluate nuclear at a standard ACF, say 80 per cent. Most loads that electricity might be called on to meet to help solve a general energy supply problem have much lower load factors. To reap the benefits of low-cost nuclear power, the load factor of new loads will have to be correspondingly high. For instance, the unit cost of nuclear electricity for electric space-heating purposes is over twice that for serving a 100 per cent ALF industrial customer. From the system planning perspective, there is a definite incentive to increase the load factor of the marginal nuclear station. From the perspective of the province as a whole, the economic attractiveness of alternative energy options, relative to electricity supply, clearly depends on the characteristics of the potential load. Part of the motivation for this note was the Amory Lovins-William Morison correspondence on the incremental cost of adding nuclear capacity to Ontario Hydro's system, summarized by R.W. Jackson in Volume 2, No. 3, of the Science Council of Canada's "Conserver Society Notes" (p. 32). The methodology used by A. Lovins in his book, *Soft Energy Paths* (1977), was to convert capacity costs for all complete energy systems into a standard cost equivalent for a barrel of oil production per day (1976 dollars) "without regard to quality of energy supplied". W. Morison of Ontario Hydro, on the other hand, assigned an efficiency premium for electric energy based on the current mix of uses of electricity. Therein lay much of the discrepancy in results and the kernel of a debate as to whether the efficiency of the incremental end uses of electricity in future will correspond to the average use today. This note calculates unit energy costs rather than the marginal capital costs required to produce the equivalent of a barrel of oil per day. It was felt that front-end capital costs, as a device to rank energy projects, can be deceptive for some technologies (e.g., hydraulic generation). The results in Tables A.1-A.3 lump capital and running costs together at a particular point in time. They may be transformed into a time series of energy costs with an assumption about running costs, and, after adjusting for conversion efficiency, may be used to calculate the life-cycle cost of energy in an end use.

The estimates developed here do not include estimates of the unpaid social costs of expanding the electric power system. This is the subject of Volume 6 of this Report, and it was discussed in the Commission's *Interim Report*. A recent study observed:

> We cannot know how great a premium we can afford to pay for a new technology unless we understand the relevant health and environmental problems of the old. Therefore, whether or not we are optimistic about new energy sources, understanding what the unpaid costs of coal and nuclear energy are is a task of the utmost importance if the public is to make well-informed decisions on energy policy.[2]

Hopefully, future studies of this kind will be able to integrate meaningfully the economic and social costs of incremental system expansion.

Space-Heating Load

The incremental cost to the system of supplying an additional megawatt hour of electricity will be sensitive to whether or not the system is in equilibrium. Currently, there is excess capacity that will persist at least until the late 1980s and perhaps on into the 1990s, depending on the load growth and the in-service date of the Darlington nuclear station. During this decade, coal-fired capacity expansion plans would not be affected if the space-heating load turned out to be twice the 1,500 MW increase projected in the "Load Management Report" (Ontario Hydro, ECD-78-6) or remained constant at 1,500 MW (the level in 1977). With excess capacity in the 1980s, the total incremental cost to the system of a marginal change in a 30 per cent load factor end use would be restricted to the cost of the fuels for the less efficient coal units, roughly $22/MW·h in 1978 dollars (see Table A.1). loads will add to distribution costs.

Table A.1 System Costs Incurred in Meeting an Increment to a Space-Heating Electricity Load with a 10 per cent Annual Load Factor[a]

	New nuclear			New coal			Existing coal		
	$/kW	$/MW·h	$/million BTU	$/kW	$/MW·h	$/million BTU	$/kW	$/MW·h	$/million BTU
Base station									
Capital[b]	85.5			48.9			0		
Operation and maintenance									
(including heavy-water upkeep)	23.0			14.1			0		
Fuel	13.2			53.8			59.2		
Subtotal	121.7			116.8			59.2		
Reserve station									
Capital[b]	0			0			0		
Operation and maintenance	0			0			0		
Fuel	21.7			23.3			23.3		
Total	143.4	54.6		140.1	53.5		82.5	31.4	
Transmission and distribution losses		4.7			4.6			2.7	
Transmission capital costs[b]	10.9			10.9			0		
Distribution capital costs[b]		4.1			4.1			4.1	
System Total – 1987$		74.3	21.8		73.1	21.4		38.2	11.2
System Total – 1978$		43.7	12.8		42.9	12.6		22.4	6.6

Notes:

a) Generation costs in 1987, expressed in 1987 dollars unless otherwise noted.

b) Annual capital charge calculated using a capital recovery factor. See "Assumptions Underlying Tables A.1, A.2, and A.3".

Sources: Ontario Hydro System Planning Division, Report 584SP, January 1979; Economics Division, Economic Forecasting Series, October 1978; and Memorandum to RCEPP, Generation Planning Processes and Reliability, 1976.

Probably in the early 1990s the period of spare coal-fired capacity will draw to a close. Changes in space-heating load will affect Ontario Hydro's capacity expansion plans for those years. Table A.1 shows that the system may be indifferent as to whether new nuclear or new coal is used to meet this load. At this point, marginal system costs would rise dramatically to about $43/MW·h in 1978 dollars, equivalent to about $13 per million BTU in 1978 dollars. The long-run incremental cost of electric space-heating load is about twice the short-run incremental cost (see costs of existing coal column in Table A.1), which, in turn, was below the system average costs in 1978.

Capital Charges

In order to calculate the unit cost of energy from a nuclear plant, the plant's capital cost was distributed over the life of the station as if customers were paying the same charge for capacity in each of the 30 years of the station's economic life. The front-end costs (current dollars expended to construct the plant, plus capitalized interest) may be viewed as the principal of a mortgage to be amortized in equal real (i.e., constant dollars of the year the station enters service) annual installments. The real interest rate (4.5 per cent) applied to the outstanding balance was taken to be roughly the difference between the nominal discount factor and the assumed inflation rate. This approach results either in a flat real stream of capital costs or in an exponentially increasing, nominal one. Details of the calculation of capital charges for the base and reserve stations are given in the "Assumptions" section at the end of this appendix.

The approximate capital cost of increments to the transmission and distribution (T&D) system were estimated from historical data. Between 1970 and 1977, real (1971 dollars) expenditures by Ontario

Hydro on its T&D system averaged $160 million per year. They were somewhat higher in the years 1975-7, averaging about $180 million. The municipal utilities spent an additional $60 million (1971 dollars) on fixed assets per year in 1970-77, a sum that was very stable in real terms. Total capital expenditures on T&D by Ontario Hydro and the utilities may be conservatively estimated to have been $1.27 billion by Ontario Hydro and $0.48 billion by the utilities over eight years. During this period, dependable peak generating capacity increased by 8,600 MW. This is an average capital expenditure on T&D of $204/kW of additional generation capacity in 1971 dollars or roughly $640/kW in 1987 dollars. Amortized over 30 years, and at the thirty per cent ACF appropriate for the space-heating load, the additional energy cost is about $15/MW·h when new generation sites require additions to the transmission system and $4.10/MW·h if existing transmission facilities are adequate but incremental distribution costs are encountered. At the higher ACFs discussed below, the unit energy costs decrease.

Reliability Penalty

A station that serves the temperature-sensitive 30 per cent load factor electric space-heating load will operate primarily in the winter months and will be down for planned maintenance in the summer. It will be assumed that the availability of the unit in winter is about 85 per cent (because of forced and maintenance outages) and that its back-up, with a 4.5 per cent ACF, is an existing oil-fired station. Because it is assumed that excess oil-fired capacity will persist long into the future, the added cost of reliability in this case is just the extra fuel cost of the oil-fired station for the duration of the coal station's outages. For new stations the reliability penalty adds about 18 per cent to energy costs.

Transmission and Distribution Losses

The total losses in the delivery of electric energy from generating stations to end-users are a function of distance, the voltage of the line, and the amount of transformation required. According to the Ontario Hydro statistical yearbooks, between 1962 and 1977 the average loss was 6.8 per cent. It was 7.7 per cent in 1976-7. In future, generation may be located farther from the load, so that a rough estimate of 8 per cent of generated power lost in transmission and distribution is assumed. The same percentage is applied to the high-load-factor customer; because he receives power at higher voltages, this will somewhat overstate his transmission losses.

Nuclear Power for High-Load-Factor Customers

During the 1980s, while nuclear capacity approaches Ontario Hydro's target share in the generating system, marginal increases or decreases in base load (55 per cent or higher ACFs) will be absorbed by existing coal-fired units, much as in the low-load-factor case. By the late 1980s or the early 1990s, however, incremental demand by high-load-factor customers will likely be met by nuclear capacity. Appendix B looks at the trade-off between building new nuclear capacity and utilizing existing fossil-fuelled stations, in part to assess the speed with which the nuclear:coal mix will increase. Tables A.2 and A.3 indicate that, in its first year of operation in 1987, a nuclear station has a 17 per cent cost advantage over a coal station supplying 65 per cent ALF customers and a 30 per cent advantage with 100 per cent ALF customers. This margin would increase over time to yield the life-cycle cost advantages frequently cited for nuclear.

The methodology used to estimate the unit cost of incremental electricity for an industrial customer with a 65 per cent ALF (e.g., a two-shift operation) and for one with a 100 per cent ALF (continuous load) parallels that used in the space-heating example. The noteworthy feature of the two base-load cases is their reliability penalty. In serving a load with a 65 per cent ALF, nuclear capacity could be expected to operate with an ACF of 52 per cent (80 per cent availability multiplied by an ALF of 65 per cent) and to require back-up from coal- or oil-fired units for the remainder of the energy delivered. A 100 per cent ALF customer would be served by a nuclear unit with a 77 per cent ACF and reserve coal capacity. The reliability penalty corresponding to the combined capital and running costs of the re-serve station is about 44 per cent in the 65 per cent ALF case and 54 per cent in the 100 per cent ALF case. The cost of reliability is high relative to base-load generation because the reserve units must be fossil-fuelled. Nuclear back-up for nuclear would be even more expensive because of the low capacity factor of the back-up station.

Table A.2 System Costs Incurred in Meeting an Increment to an Industrial Electricity Load with a 65 per cent Annual Load Factor[a]

	New nuclear			New coal			Existing coal		
	$/kW	$/MW·h	$/million BTU	$/kW	$/MW·h	$/million BTU	$/kW	$/MW·h	$/million BTU
Base station									
Capital[b]	85.5			48.9			0		
Operation and maintenance (including heavy-water upkeep)	23.0			14.5			0		
Fuel	26.6			109.8			120.7		
Subtotal	135.1			173.2			120.7		
Reserve station									
Capital[b]	24.5			24.5			0		
Operation and maintenance	7.0			7.0			0		
Fuel	27.4			27.4			30.2		
Total	194.0	34.1		232.1	40.8		150.9	26.5	
Transmission and distribution losses		3.0			3.5			2.3	
Transmission capital costs[b]		5.0			5.0			0	
Distribution capital costs[b]		1.9			1.9			1.9	
System total – 1987$		44.0	12.9		51.2	15.0		30.7	9.0
System total – 1978$		25.8	7.6		30.1	8.8		18.0	5.3

Notes:

a) Generation costs in 1987, expressed in 1987 dollars unless otherwise noted.

b) Annual capital charge calculated using a capital recovery factor. See "Assumptions Underlying Tables A.1, A.2. and A.3".

Sources: Ontario Hydro System Planning Division, Report 584SP, January 1979; Economics Division, Economic Forecasting Series, October 1978; and Memorandum to RCEPP, Generation Planning Processes and Reliability, 1976.

Table A.3 System Costs Incurred in Meeting an Increment to an Industrial Electricity Load with a 100 per cent Annual Load Factor[a]

	New nuclear			New coal			Existing coal		
	$/kW	$/MW·h	$/million BTU	$/kW	$/MW·h	$/million BTU	$/kW	$/MW·h	$/million BTU
Base station									
Capital[b]	85.5			48.9			0		
Operation and maintenance (including heavy-water upkeep)	23.0			14.8			0		
Fuel	37.4			160.4			176.4		
Subtotal	145.9			224.1			176.4		
Reserve station									
Capital[b]	24.5			24.5			0		
Operation and maintenance	7.0			7.0			0		
Fuel	48.6			50.7			55.7		
Total	226.0	25.8		306.5	35.0		232.1	26.5	
Transmission and distribution losses		2.2			3.0			2.3	
Transmission capital costs[b]		3.3			3.3			0	
Distribution capital costs[b]		1.2			1.2			1.2	
System Total – 1987$		32.5	9.5		42.5	12.5		30.0	8.8
System Total – 1978$		19.1	5.6		25.0	7.3		17.6	5.2

Notes:

a) Generation costs in 1987, expressed in 1987 dollars unless otherwise noted.

b) Annual capital charge calculated using a capital recovery factor. See "Assumptions Underlying Tables A.1, A.2, and A.3".

Sources: Ontario Hydro System Planning Division, Report 584SP, January 1979; Economics Division, Economic Forecasting Series, October 1978; and Memorandum to RCEPP, Generation Planning Processes and Reliability, 1976.

Conclusions

The estimates in Tables A.1-A.3 reflect the major components of Ontario Hydro's internal or financial costs in adding generating capacity to serve particular types of customers. They do not purport to represent the incremental social cost of generation in the future. Rather, they were designed to give an indication of the trends in Hydro's cost structure and to serve as a basis for the comparison of electric with non-electric energy investments when the latter are also made under public sector conditions.

The methodology employed spreads the capital cost (including interest payments) of the incremental capacity required to meet an end use over the life of the facility in equal real annual amounts; fuel costs are added to the annual capital charge to give a year-by-year version of life-cycle costs. This was felt to be a better input to comparisons of energy investments than standardized front-end costs, as developed by Lovins in *Soft Energy Paths*.

Our estimates are approximate. We recommend that Ontario Hydro perform system simulations to estimate more accurately the incremental costs of encouraging substitutions of electricity for fossil fuels. It would be appropriate for the Ministry of Energy to prepare comparable cost estimates of alternative means for supplying or saving the same amount of tertiary energy. The less quantifiable social costs should at least be delineated. Also, the economics of using nuclear power to substitute for oil and natural gas in such applications as industrial process heat, space heating, and urban transportation must consider the massive infrastructure costs incurred by individuals and society as a whole in converting energy-consuming systems. These should be weighed against more efficient utilization of existing capital stocks.

At least two other sets of expenditures would need to be taken in account, were the province to attempt to optimize both its energy-delivery and its energy-consuming systems jointly. Because of the seasonality of the space-heating load, decreases in system load factor may be difficult to avoid without significant additional expenditures on load-management or storage-system equipment. In practice, perhaps, the only cheap solution to the seasonality of space-heating loads may be large-diversity (i.e., summer) export contracts.

Assumptions Underlying Tables A.1 and A.3

30 per cent annual load factor (ALF): space heating, continuous over three to four months.
65 per cent ALF: industrial, 8 a.m. to 12 midnight every day.
100 per cent ALF: industrial, continuous throughout the year.

Availability of the Base Station

Availability is estimated to be 100 per cent minus the percentage outage in the three categories: forced outage (FO), maintenance outage (MO), and planned outage (PO).

Outages		750 MW Fossil	850 MW Nuclear
30% ALF	FO + MO =	15%	14%
65% ALF	FO + PO =	20%	20%
100% ALF	FO + MO + PO =	24%	23%
Availability		ACF* 750 MW Fossil	ACF 850 MW Nuclear
30% ALF		25.5%	25.8%
65% ALF		52%	52%
100% ALF		76%	77%

Note: *Annual capacity factor

Capital Costs for 4 × 850 MW Nuclear and 4 × 750 MW Coal-Fired Stations

The estimates of the total capital cost of nuclear and coal-fired stations are those given in "Ontario Hydro System Planning", (584SP, January 1979), with the exception that sunk costs (about $450 million in 1987 dollars) in the heavy-water programme have been excluded. Ontario Hydro's discount rate of 9.75 per cent was deflated by the projected long-term inflation rate of 5 per cent to yield a real discount rate of 4.5 per cent. A 30-year real capital recovery factor of 6.14 per cent was employed to derive the annual charge for capital.

Fuel Costs

Fuel costs for new fossil-fuelled and nuclear units were taken from the same Ontario Hydro document to be $24.1/MW·h for coal and $5.9/MW·h for nuclear in 1987. The least efficient of the existing coal stations, which were assumed to be the marginal units, were estimated to be 10 per cent less efficient than the hypothetical one in the document. This increases unit coal costs to $26.5/MW·h. Ontario Hydro's cost of oil in 1987 was estimated to be $59/MW·h.

Operation and Maintenance

Nuclear O&M is independent of the ALF, but coal ranges from $13.9/MW·h at 10 per cent ALF to $14.9/MW·h at 80 per cent ALF.

Reserve Station Assumptions

To be consistent with a 25 per cent reserve for the total system over the December managed firm peak, we have estimated that the additional capacity required as back-up for thermal stations as a sub-system on average over the year is equal to about 50 per cent of peak thermal capacity. It is then assumed that 50 per cent of incremental capital costs for reserve units are attributed to each base unit. Fuel costs are calculated for the ALF of the reserve station, which equals the annual load factor minus the annual capacity factor of the base station given above. The likely reserve stations appropriate to the different ALFs after the late 1980s are:

    30% ALF: existing oil-fired
    65% ALF: new coal-fired
    100% ALF: new coal-fired

This was determined by the ACF of the reserve station. Surplus existing coal units, likely under a low load-growth scenario, are assumed to be backed up by existing coal units.

Transmission and Distribution Losses

To ensure delivery of the required load, energy sent out must be augmented by about 8.7 per cent to correct for line losses of about 8 per cent, assumed on the basis of an historical analysis of losses in the T&D system.

Transmission and Distribution Unit Capital Costs

Constant-dollar expenditures by Ontario Hydro on transmission and distribution and the total expenditures of municipal utilities were aggregated for the years 1970 to 1977 and divided by the increase in system generation capacity to provide a rough estimate of T&D costs per unit of generation capacity. They were then amortized over 30 years at a 4.5 per cent real discount rate. The 1987 dollar transmission capital cost was calculated to be $465/kW, and distribution costs were $175/kW. Annual capital charges were $28.6/kW and $10.7/kW, respectively. Existing stations are not expected to require incremental transmission facilities, but incremental

Economic Considerations in Building an Incremental Nuclear Station to Replace Existing Coal-Fired Capacity

The paper by Banerjee and Waverman entitled "The Life-Cycle Costs of Coal and Nuclear Generating Stations" (RCEPP, July 1978) concluded: "The results unambiguously indicate that in terms of economic costs in Ontario, nuclear generating stations are substantially more attractive than coal-fired generating stations."

Ontario Hydro's System Planning Division circulated a report entitled 'Cost comparison of 4 × 750 MW fossil-fuelled and 4 × 850 MW CANDU nuclear generating stations" (Report No. 584SP, January 1979), which also showed that, for a wide range of scenarios of the major parameters, the accumulated discounted cash flows of a nuclear station would break even with either a U.S. or a Canadian coal-fired station entering service in 1987, well before the end of the 30-year economic life assumed for both stations at average capacity factors (ACFs) as low as 40 per cent. This appendix explores a different type of coal-fired and nuclear station comparison. It analyses the case in which the capital expenditures on the nuclear station have not yet begun, or are under way, at the same time that the system has surplus coal-fired units.

The current surplus of fossil-fuelled capacity could continue on into the mid to late 1980s because Ontario Hydro's committed construction programme, consisting almost entirely of nuclear plants, cannot be slowed down as rapidly as the load forecast is revised without significant cost penalties. The proportion of total capital cost that has already been expended (sunk) on each unit varies widely. Sunk costs, consisting of construction costs and committed components, may effectively reduce the remaining capital costs required to complete a generating unit to the extent that it becomes cost-effective to bring it into service rather than to operate existing coal-fired capacity.

The unit energy cost estimates presented here for new nuclear (i.e., with no sunk costs) and for existing coal stations are sufficiently close that, given the uncertainty in the assumptions required to calculate them, any decision to stimulate the nuclear programme in the next decade will be a political one. There appears to be little justification for advancing the in-service dates of committed or uncommitted nuclear stations in order to replace existing coal-fired stations on the grounds of reducing system fuelling costs. In this case, the economic argument that favoured nuclear over coal in a comparison of two new stations is no longer clear-cut.

This has important implications for the reactor order level of the nuclear industry in the province should load growth turn out to be at, or below, Ontario Hydro's 1979 load forecast. Unless it became government policy to accelerate the construction of nuclear stations, growth of the system would eliminate excess capacity by the early 1990s. Assuming that the period of surplus capacity is temporary, measures that could take advantage of it should be focused on the relatively short term (i.e., the 1980s). For instance, it would be preferable to export surplus power and energy to the U.S. than to incur a long-term deterioration in the system load factor brought about by promoting electrical space heating. On the other hand, the existence of excess peaking capacity, even though temporary, should enhance the attractiveness of some alternative energy systems that require a back-up energy source.

Methodology

The emphasis in the comparison of a new nuclear station with an existing coal-fired station switches from life-cycle costing of the alternatives to a comparison of unit costs in the early years of operation. Life-cycle costing is the relevant tool for investment decision-making when no surplus capacity would be created by the new station. However, if a new nuclear unit is to displace an existing coal-fired unit, it should not enter service until its unit energy cost is lower than that of the station it substitutes for. Running the coal station for one or more years and then bringing on the nuclear plant may be a lower-cost option than bringing the nuclear unit on right away. This is equivalent to observing that as long as the running cost of the existing coal-fired station is lower than the unit energy cost of the nuclear station (i.e., annual capital plus running costs), it is cost-effective to continue running the coal-fired station. The calculation of nuclear's unit energy cost will be sensitive to the station's expected ACF in

the year it enters service, which in turn will depend on the load growth that is forecast, the impact of any load-management measures, and the share of nuclear in the generation mix. Also, real costs of existing coal and new nuclear will change over time if fuel costs and construction costs escalate at different rates. Thus, the major new complexity in this analysis over and above that of the comparison of new stations is that the optimal in-service year of the nuclear unit must be selected in the context of a cost structure that changes from year to year and from scenario to scenario.

Thus far, it has been implicit that the alternative to an increment in nuclear capacity is a surplus coal-fired unit. However, the current excess capacity is composed largely of oil- and gas-fired units (namely Lennox, 2,200 MW, Hearn, 1,200 MW, and combustion turbine units). The running costs of an oil-fired station are over twice those of one of the system's coal-fired stations and by the late 1980s they are expected to be nearly three times as high. This cost disadvantage with respect to coal ensures that, as coal-fired stations are pushed up the stacking order by nuclear, coal will assume the peaking role intended for oil-fired capacity. As demand grows, it will be worth while to use coal-fired capacity to serve loads with ACFs greater than 15-20 per cent, rather than to generate power from existing oil-fired units. Nonetheless, the existing oil-fired plants will continue to play a valuable part in providing reserve margin. A likely scenario would be that, by the late 1980s, committed nuclear plants will displace coal-fired capacity into the peaking mode, relegating oil-fired capacity to a fairly permanent reserve role akin to that of combustion turbine units. The critical question is still whether nuclear unit energy costs are in fact lower than the running costs of a coal-fired unit at a time when there is surplus coal-fired capacity.

In the course of the calculations, it will be assumed that operation and maintenance expenditures continue on all existing fossil-fuelled stations, so that the marginal running costs of these stations will be taken to be simply the cost of the fuel. The projection of fuel costs for both fossil-fuelled and nuclear stations will depend heavily on the assumptions made regarding their long-term escalation rates. The fuel costs contained in the system planning report cited above served as a good starting point.

Since the capital cost of the fossil-fuelled station is sunk, the interest payments and depreciation of the initial capital cost of the station will go on regardless of whether the station produces power or not. For this reason, no capital charges are attributed to the station costs in the comparison. For the same reason the capital expenditures embedded in heavy-water plants that have been completed are excluded. The latter adjustment reduces the total capital cost of a 4 × 850 MW nuclear station from the $5.2 billion given in Ontario Hydro document No. 584SP to $4.7 billion in 1987 dollars.

An economic cost-recovery method such as the one employed in Appendix A yields substantially lower capital charges in the first year of operation than either the sinking fund or the straight-line deprecia-tion methods used by the Ontario Hydro System Planning Division report cited above in its calculation of nuclear capital costs in the first year of operation (see Table B.1). However, the way capital costs are distributed amongst customers over the lifetime of the plant via the depreciation policy that is in force is not relevant in evaluating an investment decision. Depreciation policy nonetheless has significant implications for Hydro's rates and the need for debt financing. This is noted here because these factors may be considered should the economic choice not be clear- clear-cut.[1]

Table B.1 Comparison of System Economics: First Year of Operation of a New Nuclear Station and an Existing Coal-fired Station (1987 $/MW·h)[a]

| | New nuclear | | |
	65% ACF	80% ACF	Existing U.S. coal
Capital	14.8[b]	12.4[b]	–
Fuel[c]	5.9	5.9	26.5
Operation and maintenance	4.1	3.4	–
Subtotal	24.8	21.7	26.5
Transmission capital costs[d]	5.0	4.1	–
Total	29.8	25.8	26.5

Notes:

a) Omitted cost items are common among alternatives in this case.

b) Capital cost of $4.7 billion for a 4 × 850 MW station, applying a capital recovery factor of 0.0614 or $84.9/kW per year for 30 years. In the first year, the sinking fund capital charge is $144/kW and straight line depreciation gives about $185/kW.

c) Source – Ontario Hydro, System Planning Division, Report 584SP, January 1979: Coal costs increased 10% to reflect lower combustion efficiency of marginal stations.

d) RCEPP estimate, see Assumptions for Tables A.1-A.3.

Drawing on the data in document No. 584SP and structuring the analysis along the lines of the assumptions just made allows us to make an approximate cost comparison of a megawatt hour of electricity generated by a new nuclear station with one generated by an existing coal-fired station. We will start with the cost picture in 1987 and then, in this partial analysis, examine the likely changes in the comparison if it were made either earlier or later.

In the first year of operation, an 850 MW CANDU unit is expected to be available 66.3 per cent[2] of the time, so that generation costs are likely to fall closer to those given in the 65 per cent ACF column. Of course, if the ACF of the nuclear plant were lower than 65 per cent, the capital charge would increase proportionately. At a 40 per cent ACF, nuclear's cost would rise to $39/MW·h. Coal fuel costs are for U.S. bituminous, the marginal type of coal, as it is Ontario Hydro's intention to utilize all western Canadian coal contracted for, if possible. The 1987 dollar coal cost in document No. 584SP is augmented by 10 per cent to reflect the lower combustion efficiency that is possible in marginal coal stations. Table B.1 summarizes the relevant results, omitting cost items that would be common between the two alternatives.

Conclusions

Without incremental transmission capital costs, the analysis summarized in Table B.1 indicates a slight edge for nuclear at the 65 per cent ACF. When additional transmission expenditures are involved, the balance shifts in favour of the existing coal-fired station. Given the uncertainty surrounding the estimates, the costs in 1987 are so similar that one may safely conclude that considerations other than ones of economic optimization will determine whether an additional nuclear station should be built.

It is not feasible to consider an in-service date for any new nuclear station (after Bruce B) prior to 1987. If the comparison in Table B.1 were to be repeated with an in-service year after 1987, Ontario Hydro's current escalation forecasts indicate that the cost of coal-fired power would decline marginally relative to that of nuclear, since coal-fuelling costs increase at a slower rate than nuclear construction expenses. One may conclude that Darlington (as long as little capital is committed), and the nuclear stations after it, should, on cost grounds, enter service only as rapidly as warranted by the forecast load growth.

The effect on the unit cost of nuclear electricity of sunk costs in stations under construction is to reduce the capital charge item in Table B.1. For instance, if $1 billion had already been committed on the hypothetical station in the table, the capital cost then required to obtain a flow of energy from the plant would become $3.7 billion. The charge for capital would fall to $11.70/MW·h and the total unit energy cost would be revised to $26.70/MW·h, roughly the same as the fuelling cost for the existing coal-fired station. Therefore, once about one-quarter of the capital expenditures on a nuclear plant have been made, it becomes worth while to finish the plant on schedule regardless of load growth, as long as it can then displace a base-load coal-fired station. This implies that only within about three or four years from the start of construction is there the financial flexibility to defer a station without cost penalty (unless there are other constraints such as delays in the completion of transmission facilities).

Nuclear capacity is expected to achieve Ontario Hydro's desired configuration in the generating system during the period in which the four Darlington units are commissioned. Should it be decided that a steady flow of nuclear orders was required to keep the nuclear option open, there would be no significant cost penalty to Ontario Hydro if the new nuclear stations entered service with an ACF of about 65 per cent and, in the process, created surplus coal-fired capacity. Since an ACF for the incremental nuclear unit of less than 65% is likely by the early 1990s, the cost penalty of advancing nuclear units could start to mount. In addition, if better investment opportunities are foregone, such a policy would not enhance the province's overall economic performance.

Fuel Price Scenarios Used in the Analysis of Co-Generation, Home Heat Conservation, and Solar Heating

The economic attractiveness of measures that improve the efficiency with which fossil fuels and electricity are consumed depends largely on the investor's expectations concerning future energy prices, his desired rate of return, and the pay-back period he finds satisfactory. The cost-effectiveness and implementation rates of the three energy investment alternatives examined in Chapter 5 are quite sensitive to the particular perception of these factors that individuals or institutions adopt. The rate-of-return and pay-back-period assumptions are introduced in the course of the analysis of each technology. The energy price scenarios require further elaboration here.

Separate fuel scenarios appropriate to the cost-benefit analysis of industrial co-generation and the residential space-heating measures (i.e., insulation and solar heating) were developed. Scenarios of the cost to industry of natural gas and coal boiler fuels and the base-load electricity they would displace, were used in the co-generation study. The home-heating examples focused on the savings of natural gas and electricity that were feasible at residential rates. All fuel prices were formulated in real terms, that is, in dollars with 1978 purchasing power, and were converted so that they could ultimately be expressed in 1978 dollars per million British Thermal Units delivered to the final use. In all cases fuel prices were assumed to stabilize in real terms by the year 2000. The price scenario used in the co-generation and space-heating cost-benefit analyses are compiled in Tables C.1 and C.2, respectively. The tertiary energy costs for space heating are plotted in Figure C.1.

Table C.1 Energy Price Assumptions Used in Co-Generation Implementation Study

	Gas Prices						Electricity Prices					
	($/million BTU)			Usage charge ($/kW·h)			Standby charge ($/kW·h)			Demand charge ($/kW·h)		
Year	Low	Med.	High	Low	Med.	High	Low	Med.	High	Low	Med.	High
1980	2.4	2.4	2.5	0.02	0.02	0.02	8.4	8.4	8.5	59.5	59.5	59.5
1981	2.6	2.6	2.8	0.02	0.02	0.02	8.7	8.7	9.0	62.1	62.1	64.1
1982	2.7	2.7	3.0	0.02	0.02	0.03	9.1	9.1	9.5	64.9	64.9	67.9
1983	2.9	2.9	3.3	0.03	0.03	0.03	9.5	9.5	10.10	67.7	67.7	72.0
1984	2.9	2.9	3.4	0.03	0.03	0.03	9.4	9.5	10.30	67.0	67.7	73.4
1985	2.9	3.0	3.4	0.02	0.03	0.03	9.3	9.5	10.51	66.4	67.7	74.9
1990	3.0	3.3	3.8	0.02	0.03	0.03	8.9	9.5	11.6	63.1	67.7	86.7
1995	3.1	3.6	4.1	0.02	0.03	0.03	8.4	9.5	12.81	60.0	67.7	91.3
2000	3.2	3.9	4.5	0.02	0.03	0.04	8.0	9.5	14.14	57.1	67.7	100.8

Note: Coal prices ($1978) are constant over the time period at: 1.85, 2.22, 2.35 $/million BTU for low, medium, and high cases. All prices remain constant in real terms after the year 2000.

Table C.2 Residential Fuel Price Scenarios ($1978/million BTU delivered)

	Low			Medium			High			Electricity Short-run marginal cost pricing	Long-run marginal cost pricing
Year	Oil	Gas	Elec.	Oil	Gas	Elec.	Oil	Gas	Elec.		
1980	6.5	5.6	8.8	6.5	5.6	8.8	6.5	5.7	8.9	6.6	8.1
1981	6.7	5.8	9.1	6.7	5.8	9.1	6.7	6.1	9.4	6.6	9.2
1982	7.0	6.0	9.5	7.0	6.0	9.5	7.0	6.6	10.0	6.7	10.5
1983	7.2	6.3	10.0	7.2	6.3	10.0	7.2	7.0	10.6	6.7	12.0
1984	7.2	6.3	9.9	7.3	6.4	10.0	7.3	7.1	10.8	6.8	13.7
1985	7.2	6.3	9.8	7.4	6.5	10.0	7.5	7.2	11.0	6.8	13.8
1990	7.5	6.4	9.3	8.1	6.9	10.0	8.6	7.8	12.2	7.1	14.1
1995	7.7	6.6	8.8	8.7	7.1	10.0	9.6	8.4	13.4	13.7	14.5
2000	7.9	6.8	8.4	9.4	8.0	10.0	10.8	9.0	14.8	14.1	14.8

Source: For assumptions, see fuel price scenario section.

Natural Gas Prices

Three natural gas price scenarios were derived from projections of the Canadian crude oil price delivered to Toronto. In the low scenario, the Toronto "city-gate" price of natural gas is 85 per cent of the BTU equivalent price of oil, which rises to $18 per barrel in 1983 (from $15 per barrel in 1979) and reaches $20 per barrel by the year 2000. The medium case followed the low scenario to 1983 and then converged to an oil price of $25 per barrel by 2000. The high case assumed 100 per cent BTU equivalence with oil throughout the scenario, in which the Canadian oil price rose to $25 per barrel in the year 2000. The industrial and residential rates were set at the Toronto city-gate price plus a constant real margin equal to that currently allowed by the Consumers' Gas System: residential, $1.20 and industrial $0.30 per million BTU. To compensate for conversion and distribution losses in the home-heating system (assumed to have a total efficiency of 60 per cent in future), the effective residential gas rate was augmented by a factor of two-thirds. This allows gas-heating costs to be compared with electrical space heating (100 per cent conversion and distribution efficiency) and conservation measures (tertiary energy savings, i.e. no conversion losses) on an equivalent basis. These scenarios indicate that natural gas would be a cheaper fuel for space heating than electricity in all cases, except in the low-electricity scenario after the mid 1990s.

In the fast-moving world of oil pricing, the Canadian oil price projections from which the natural gas scenarios were derived may turn out to be on the low side. On the other hand, a government decision to de-couple prices of oil and gas may result in natural gas not following the Canadian price of crude to world levels. Nevertheless, should the scenarios presented understate the price of natural gas in the 1980s, the results of the cost-benefit analyses performed for the 1990s could be applied to earlier years. In so doing, the penetration of gas-fired co-generation would probably suffer, while additional space-heating conservation measures would become viable much earlier.

Electricity

Electricity price scenarios were developed on two bases: first, the current rate structure (accounting or average cost pricing) and, second, marginal or incremental system costs of meeting respective end uses. Three sets of growth rates were applied to 1979 industrial and residential rates to calculate the average cost scenarios. The low scenario was contained in Ontario Hydro's "Long-Range Financial Forecast 78 1201" and applied in the 1979 load forecast. It results in real electricity price increases to 1982 followed by steady real declines to the year 2000. Rates in the year 2000 are equal in real terms to rates in 1979. The medium scenario keeps real electricity rates constant after 1983. The high scenario has faster real price increases to 1983, followed by a 2 per cent average real annual growth rate to 2000.

The incremental cost scenarios are derived from the results in Appendix A. The annual load factor (ALF) of space-heating loads was taken to be about 30 per cent. At this ALF there is little difference in unit energy cost between new nuclear and new coal-fired capacity (see Figure C.1). However, if short-run incremental costs (i.e., running costs) determine rates, then Ontario Hydro's current excess coal-fired capacity would lead to unit energy costs for the 1980s that are roughly half what they would be under long-run incremental costing (i.e., including incremental capacity costs) and about 15 per cent below current average cost-based tariffs. In the 1980s, electricity priced on the basis of short-run incremental costs competes with the medium natural gas scenario. The elimination of excess coal capacity by 1990 leads to a phased-in doubling of the electricity space-heating tariff. To avoid committing the system to long-term loads during a short-term capacity surplus, the long-run incremental cost scenario advances the short-run incremental cost scenario by 10 years. The high average cost scenario intersects the marginal cost scenario in about the year 2000. It may therefore be seen as a gradual transition to incremental cost pricing.

The economics of co-generation was analysed from a public sector perspective using Ontario Hydro's short-run incremental costs at annual capacity factors of 65 per cent and 80 per cent.

During the 1980s, the savings to Ontario Hydro brought about by additional co-generation installations were assumed to be coal fuel costs. By the late 1980s, nuclear units will most likely supply all base loads, so that co-generation, which typically operates in a base load mode, will compete with the total unit energy cost of a new nuclear plant.

Coal

The three coal scenarios differentiate between the cost of coal to Ontario Hydro, the cost to private industry also located on the Great Lakes, and the cost to large industrial users about 160 km inland. All assume that prices remain constant in real terms after 1980. In 1978 Hydro's average coal costs were $44 per short ton, equivalent to $1.70 per million BTU.[1] The base price of coal to Ontario Hydro is set at $1.85 per million British Thermal Units in 1978 dollars. The premium for an industrial co-generator who must negotiate his coal contract independent of Hydro is set at $0.37, bringing his post-1980 cost to $2.22 per million BTU. Additional transportation costs to move the coal off the lakes raise the price to $2.35 per million BTU for the inland industrial customer.
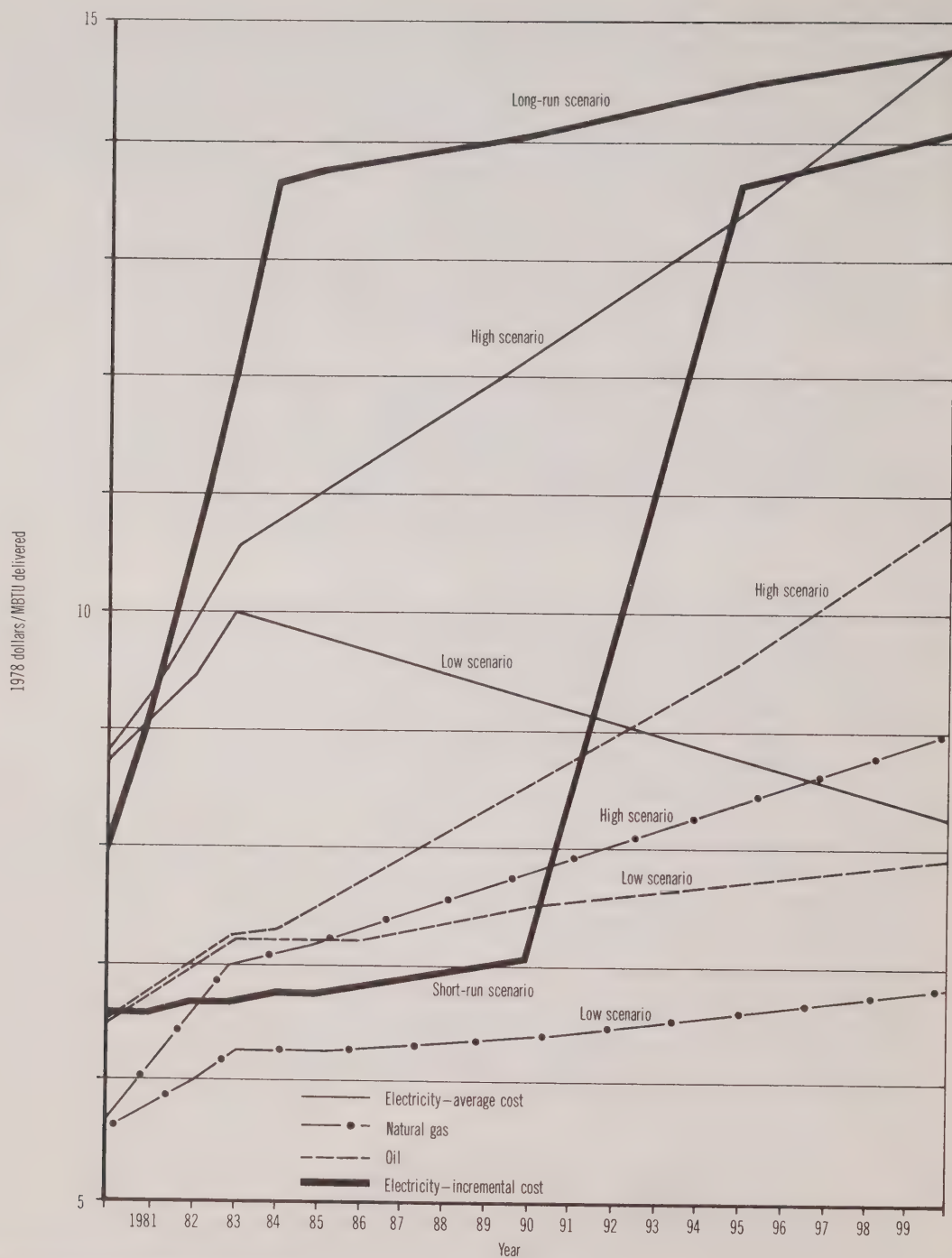
Note: Conversion efficiencies assumed — electricity 100%
— gas 60%
— oil 60%

Source: RCEPP.

Co-generation

Figure D.1 Basic Co-generation Technology
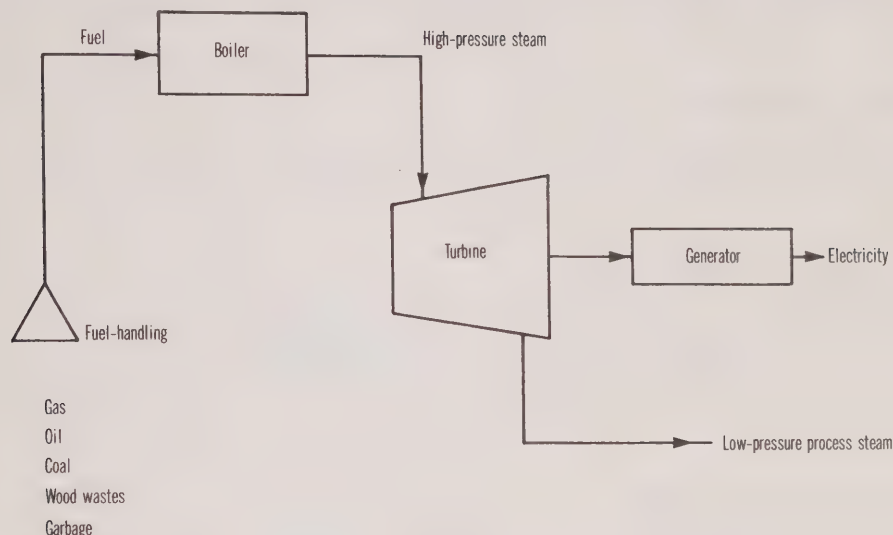
Source: RCEPP.

Unit Sizes Assuming 50 kW/1,000 pounds of steam per hour

Maximum steam demand (1,000 pounds/hour)	Installation size (MW)
100	5
200	10
400	20
800	40

Table D.1 Capital and Operating Cost Assumptions for Co-generation Units (1978 dollars)

Installation size (MW)	Boiler fuel	Capital cost (New) ($/kW)	Capital cost (Retrofit)	Operating cost (Excluding fuel) ($/kW)
5	gas	700	1,131	15
5	coal	1,400	2,262	15
10	gas	505	859	15
10	coal	1,010	1,717	15
20	gas	370	709	15
20	coal	740	1,418	15
40	gas	325	572	15
40	coal	650	1,143	15

Sources: Gas Capital Costs. "Survey of Costs Associated with Industrial Cogeneration in Ontario", D. Dick, in A. Juchymenko, ed., "The Economics of Industrial Cogeneration," p. 13. Ratio of Coal to Gas Costs, D.K. Rivera, Babcock and Wilcox. Operating Cost, Leighton and Kidd, " Report on Industrial By-Product Power", RCEPP, May 1977. Retrofit costs were calculated by applying to the costs for new systems the retrofit cost premiums implicit in Figure 7, Leighton & Kidd, "Report on Industrial By-Product Power", RCEPP, May 1977.

Measures of the Cost-Effectiveness of Co-Generation: Net Present Value and Payback Period

1. $\text{NPV} = (-K \cdot \text{CAP}) + \sum_{i=1}^{2} \dfrac{(1-\text{MTR}) \cdot (\text{AS}_i - \text{AC}_i) + (\text{MTR} \cdot \frac{\text{CAP}}{2})}{(1+\text{DR})^i} + \sum_{i=3}^{30} \dfrac{(1-\text{MTR}) \cdot (\text{AS}_i - \text{AC}_i)}{(1+\text{DR})^i}$

2. CRUDE PB = N, such that

$$\sum_{i=1}^{2} (1-\text{MTR}) \cdot (\text{AS}_i - \text{AC}_i) + (\text{MTR} \cdot \frac{\text{CAP}}{2}) + \sum_{i=3}^{N} (1-\text{MTR}) \cdot (\text{AS}_i - \text{AC}_i) \geq K \cdot \text{CAP}$$

3. DISCOUNTED PB = N', such that

$$\sum_{i=1}^{2} \dfrac{(1-\text{MTR}) \cdot (\text{AS}_i - \text{AC}_i) + (\text{MTR} \cdot \frac{\text{CAP}}{2})}{(1+\text{DR})^i} + \sum_{i=3}^{N'} \dfrac{(1-\text{MTR}) \cdot (\text{AS}_i - \text{AC}_i)}{(1+\text{DR})^i} \geq K \cdot \text{CAP}$$

WHERE:

NPV	=	net present value (1978$)
PB	=	pay back period (years)
AS_i	=	electricity savings in year i = $(\text{DC}_i + \text{LF} \cdot 8760 \cdot \text{UC}_i) \cdot \text{CAP}$
AC_i	=	additional operating costs in year i = $(\text{BFP}_i \cdot \text{HR} \cdot \text{LF} \cdot 8760 + \text{OM} + \text{SBC}_i) \cdot \text{CAP}$
CAP	=	installation size (kw)
K	=	capital cost, installed ($/kw)
MTR	=	marginal tax rate
DR	=	discount rate
DC_i	=	Hydro demand charge in year i ($/kw)
LF	=	load factor (%)
UC_i	=	Hydro usage charge in year i ($/kwh)
BFP_i	=	boiler fuel price in year i ($/MBTU)
HR	=	heat rate, or additional energy requirements (MBTU/kwh)
OM	=	facility operating and maintenance costs ($/kw)
SBC_i	=	Hydro standby charge in year i

Reducing Heat Loss in Non-Apartment Dwellings

As long as the marginal cost of added insulation increases linearly over the range of R values considered possible, then the following defines the optimum R value for attics. It also applies, with reservations, to exterior walls above grade, and to foundation walls below grade.

$$R_{optimum} = \sqrt{\frac{24 \cdot DD \cdot C_D \cdot LCC_E}{KI \cdot B \cdot E}}$$

where $LCC_E = \sum_{i=1}^{N} \frac{EP_i}{(1 + dr)^i}$

and:

DD = Annual degree days (°F)

C_D = Experience factor (assumed equal to 1.0)

LCC_E = Discounted cost of energy over lifetime of insulation investment ($/BTU)

N = Investment lifetime (years)

EP_ib = Energy price in year ($/BTU)

dr = Real discount rate

B = Installation cost ($/square foot R)

E = Heating system efficiency (0.60 for gas or oil; 1 for electricity)

KI = Initial cost adjustment arising from mortgaging investment

Energy Conversion Factors

1 million BTU = 1.055 GJ (gigajoules)

1 GJ = 0.948×10^6 BTU (British Thermal Units)

Reservations Regarding the Calculation of the Optimum R Value

1. Exterior Walls: Research conducted to date indicates that incremental costs for higher R values are approximately linear only up to R35 in single-wall construction. As no scenario suggested insulating above R27 in the walls, the formula should be applicable. Above R16, however, studs may need to be wider than the four-inch ones currently being used.

2. Basement Walls below Grade: An accurate method for determining heat loss to the ground is not at present available, and appropriate degree-day values for ground temperatures adjacent to walls are not known. Ground water may keep the temperature of the ground adjacent to the foundation wall lower than is commonly expected, but this has yet to be fully investigated. In addition, it is not clear what is the appropriate design temperature for most basement areas.

HUDAC (Reference 11) recommends: (a) below-grade degree days = 0.7 × number of above-grade degree days; (b) basement air design temperature = 0.9 × living-area design temperature.

3. The degree-day method of determining heat loss, even adjusted by the "experience" factor, C_D, to compensate for inaccuracies of the conventional method, is still thought to be a relatively inaccurate method of calculating heat loss from buildings with higher insulation levels and wild, or background, heat gains from people, appliances, etc. A Saskatchewan Research Council paper (Reference 12) has recommended that $C_D = 1$, rather than its more conventional value of 0.75, when it can better approximate the actual heat loss.

Cost-effectiveness of triple glazing and R 10 shutters compared with double glazing

D. Eyre, in a paper entitled "Optimizing the Design of Windows on a South-Facing Wall" (Reference 3) estimates the incremental cost of triple- over double-glazed windows to be $4.60/square foot. The extra layer of glass raises the R factor of the window from 2 to 3 and so results in annual energy savings of:

$$(\frac{1}{RD} - \frac{1}{RT})\cdot 24 \cdot DD \cdot CD = (0.5 - 0.33)\cdot 24 \cdot 7{,}500.1 = 30{,}000 \text{ BTU (Reference 4.)}$$

where,

RD = R value for a double-glazed window = R2

RT = R value for a triple-glazed window = R3

DD = Annual degree days for Malton, Ontario = 7,500 (Reference 4)

CD = Experience factor (Reference 4)

Evaluating the energy savings at the highest electricity rate, which is $14.8 per million BTU in the year 2000, the undiscounted pay-back on the incremental investment would be more than 10 years. Currently, in a gas-heated home, it would be more than 30 years. The economic viability of triple-glazing is some years off.

Shutters, to reduce heat loss at night, have similar economics. Apart from the drawback of having to open and close them, R10 shutters that are closed during the night for 10 hours only increase the effective daily R value to 3.1 from 2, assuming double-glazed windows. The Saskatchewan Research Council paper cited above estimates the incremental cost of shutters to be $5-$10 per square foot.

References

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Optimum R Values for Attic Insulation for New Homes under Various Home-heating-fuel Price Scenario's, Discount Rates, Pay-back Periods, and Financing Assumptions[a]

Fuel price Scenario[b]	Year of instal-lation of insulation	5% real discount rate		25% real discount rate		25% real discount rate with 30-yr mortgage at 4%	
		30-year pay-back	5-year pay-back	30-year pay-back	5-year pay-back	30-year pay-back	5-year pay-back
Natural Gas							
Low	1980	30.8	15.8	15.3	12.4	30.1	24.3
	2000	31.7	16.8	16.2	13.3	31.8	26.1
Medium	1980	32.0	15.8	15.5	12.4	30.4	24.3
	2000	34.4	18.3	17.5	14.4	34.5	28.3
High	1980	33.8	16.4	16.1	12.8	31.7	25.2
	2000	36.6	19.4	18.7	15.3	36.7	30.1
Electricity							
Low	1980	36.7	19.8	19.0	15.5	37.3	30.5
	2000	35.3	18.7	18.0	14.8	35.3	29.0
Medium	1980	38.1	19.8	19.2	15.5	37.7	30.6
	2000	38.4	20.4	19.6	16.1	38.5	31.6
High	1980	42.5	20.3	20.0	15.9	39.4	31.2
	2000	46.9	24.9	23.9	19.6	47.0	38.5

Notes:
a) Degree Day assumption is 6827, appropriate for the city of Toronto.
b) See text for description of scenarios.
Source: RCEPP

Table E.2 "Typical" Home

House type	Proportion of total non-apartment starts
A. The typical home is a composite of	
Single-1 story	38%
Single-2 storey	19%
Semi-detached	15%
Duplex	13%
Row	15%
Total	100%
B. Surface areas and volume of composite	
Floor	1,150 square feet
Attic	890 square feet
Exterior wall (net of window)	980 square feet
Basement wall (net of window)	690 square feet
Volume	5,000 cubic feet

Source: Reference 1.

Table E.3 Insulation Levels in New Dwelling

Case A. All home-heating fuels
Attics: R28
Exterior walls: R12
Basement walls (average): R10
Case B.
Attics: electrically heated R20; gas-heated R10
Exterior walls: electrically heated R12; gas-heated R10
Basement walls (average): electrically or gas-heated R5

Sources:
Case A) Ontario Building Code, p.409, Regulation 9.26.4, as revised August 1979.
Case B) Middleton Associates-estimated practice prior to introduction of mandated minimum insulation standards.

Table E.4 Energy Savings and Costs: Typical Gas-heated House (7,500 degree days — low gas price scenario)

	Case A					Case B				
	1980	1985	1990	1995	2000	1980	1985	1990	1995	2000
Attic	(existing level R28)					(existing level R10)				
Optimal R	32.3	32.9	33.0	33.2	33.2	32.3	32.9	33.0	33.2	33.2
Annual energy savings	0.76	0.85	0.87	0.9	0.9	11.06	11.15	11.17	11.2	11.2
Cost–$	65	74	76	79	79	337	346	348	351	351
Exterior wall	(existing level R12)					(existing level R10)				
Optimal R	16.5	16.8	16.9	17.0	17.0	16.5	16.8	16.9	17.0	17.0
Annual energy savings	4.01	4.2	4.26	4.32	4.32	6.95	7.14	7.2	7.26	7.26
Cost–$	287	306	312	319	319	414	433	439	446	446
Basement wall	(existing level R10)					(existing level R5)				
Optimal R	13.1	13.3	13.4	13.5	13.5	13.1	13.3	13.4	13.5	13.5
Annual energy savings	2.94	3.08	3.15	3.22	3.22	15.36	15.5	15.57	15.64	15.64
Cost–$	138	149	153	157	157	362	373	377	381	381
Vapour barrier/heat exchanger										
Annual energy savings	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02
Cost–$	500	500	500	500	500	500	500	500	500	500
Passive solar										
Annual energy savings	5	5	5	5	5	5	5	5	5	5
Total										
Tertiary energy saved	28.73	29.15	29.3	29.41	29.41	54.39	54.81	54.96	55.12	55.12
Cost–$	990	1,029	1,041	1,055	1,055	1,613	1,652	1,664	1,678	1,678

Note: Energy savings in 10^6 BTU; costs in 1978 dollars.

Table E.5 Energy Savings and Costs: Typical Gas-heated House (7,500 degree days — medium gas price scenario)

	Case A					Case B				
	1980	1985	1990	1995	2000	1980	1985	1990	1995	2000
Attic	(existing level R28)					(existing level R10)				
Optimal R	34.8	35.8	36.5	36.9	37.2	34.8	35.8	36.5	36.9	37.2
Annual energy savings	1.11	1.24	1.33	1.38	1.41	11.41	11.54	11.63	11.68	11.71
Cost–$	102	117	128	135	139	374	390	400	408	411
Exterior wall	(existing level R12)					(existing level R10)				
Optimal R	17.8	11.3	18.7	18.9	19.0	17.8	18.3	18.7	18.9	19.0
Annual energy savings	4.77	5.06	5.24	5.36	5.42	7.71	8.00	8.18	8.30	8.36
Cost–$	368	401	424	439	447	495	528	551	566	574
Basement wall	(existing level R10)					(existing level R5)				
Optimal R	14.1	14.5	14.8	15.0	15.1	14.1	14.5	14.8	15.0	15.1
Annual energy savings	3.60	3.86	4.03	4.13	4.19	16.04	16.28	16.45	16.55	16.61
Cost–$	184	202	215	224	228	409	427	440	448	453
Vapour barrier/heat exchanger										
Annual energy savings	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02
Cost–$	500	500	500	500	500	500	500	500	500	500
Passive solar										
Annual energy savings	5	5	5	5	5	5	5	5	5	5
Total										
Tertiary energy saved	30.50	31.18	31.62	31.89	32.04	56.18	56.84	57.28	57.55	57.70
Cost–$	1,154	1,220	1,267	1,298	1,314	1,778	1,844	1,891	1,921	1,938

Note: Energy savings in 10^6 BTU; costs in 1978 dollars.

Table E.6 Energy Savings and Costs: Typical Gas-heated House (7,500 degree days – high gas price scenario)

	Case A					Case B				
	1980	1985	1990	1995	2000	1980	1985	1990	1995	2000
Attic	(existing level R28)					(existing level R10)				
Optimal R	35.4	36.7	37.5	38.1	38.4	35.4	36.7	37.5	38.1	38.4
Annual energy savings	1.20	1.36	1.45	1.52	1.55	11.50	11.66	11.75	11.82	11.85
Cost–$	112	132	144	153	157	384	404	416	425	429
Exterior wall	(existing level R12)					(existing level R10)				
Optimal R	18.1	18.8	19.2	19.5	19.6	18.1	18.8	19.2	19.5	19.6
Annual energy savings	4.95	5.32	5.51	5.65	5.70	7.89	8.26	8.45	8.51	8.64
Cost–$	389	433	459	478	484	516	560	586	605	611
Basement wall	(existing level R10)					(existing level R5)				
Optimal R	14.4	14.9	15.2	15.5	15.6	14.4	14.9	15.5	15.5	15.6
Annual energy savings	3.80	4.08	4.25	4.41	4.46	16.22	16.50	16.67	16.83	16.88
Cost–$	197	220	233	247	251	503	516	523	531	533
Vapour barrier/heat exchanger										
Annual energy savings	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02
Cost–$	500	500	500	500	500	500	500	500	500	500
Passive solar										
Annual energy savings	5	5	5	5	5	5	5	5	5	5
Total										
Tertiary energy saved	30.97	31.78	32.21	32.60	32.72	56.63	57.44	57.89	58.26	58.39
Cost–$	1,198	1,286	1,336	1,378	1,392	1,903	1,980	2,025	2,061	2,073

Note: Energy savings in 10^6 BTU; costs in 1978 dollars.

Table E.7 Energy Savings and Costs: Typical Electrically Heated House (7,500 degree days – medium electricity price scenario)

	Case A					Case B				
	1980	1985	1990	1995	2000	1980	1985	1990	1995	2000
Attic	(existing level R28)					(existing level R20)				
Optimal R	38.1	38.4	38.4	38.4	38.4	38.1	38.4	38.4	38.4	38.4
Annual energy savings	1.52	1.55	1.55	1.55	1.55	3.80	3.83	3.83	3.83	3.83
Cost–$	153	157	157	157	157	274	278	278	278	278
Exterior wall	(existing level R12)					(existing level R12)				
Optimal R	19.5	19.6	19.6	19.6	19.6	19.5	19.6	19.6	19.6	19.6
Annual energy savings	5.65	5.70	5.70	5.70	5.70	5.65	5.70	5.70	5.70	5.70
Cost–$	478	484	484	484	484	478	484	484	484	484
Basement wall	(existing level R10)					(existing level R5)				
Optimal R	15.5	15.6	15.6	15.6	15.6	15.5	15.6	15.6	15.6	15.6
Annual energy savings	4.41	4.46	4.46	4.46	4.46	16.92	16.97	16.97	16.97	16.97
Cost–$	249	252	252	252	252	473	476	476	476	476
Vapour barrier/heat exchanger										
Annual energy savings	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02
Cost–$	500	500	500	500	500	500	500	500	500	500
Passive solar										
Annual energy savings	5	5	5	5	5	5	5	5	5	5
Total										
Tertiary energy saved	32.60	32.73	32.73	32.73	32.73	47.30	47.43	47.43	47.43	47.43
Cost–$	1,380	1,393	1,393	1,393	1,393	1,725	1,738	1,738	1,738	1,738

Note: Energy savings in 10^6 BTU; costs in 1978 dollars.

Table E.8 Energy Savings and Costs: Typical Electrically Heated House (7,500 degree days — Hydro short-run marginal cost electricity price scenario)

	Case A					Case B				
	1980	1985	1990	1995	2000	1980	1985	1990	1995	2000
Attic	(existing level R28)					(existing level R20)				
Optimal R	40.9	44.0	47.4	50.0	50.7	40.9	44.0	47.4	50.0	50.7
Annual energy savings	1.80	2.08	2.34	2.52	2.56	4.08	4.36	4.62	4.80	4.84
Cost–$	195	242	294	333	343	316	363	454	454	464
Exterior wall	(existing level R12)					(existing level R12)				
Optimal R	20.9	22.5	24.2	25.6	25.9	20.9	22.5	24.2	25.6	25.9
Annual energy savings	6.26	6.86	7.40	7.61	7.89	6.26	6.86	7.40	7.61	7.89
Cost–$	567	669	777	866	885	567	669	777	866	885
Basement wall	(existing level R10)					(existing level R5)				
Optimal R	15.9	17.0	18.3	19.4	19.6	15.9	17.0	18.3	19.4	19.6
Annual energy savings	4.61	5.11	5.63	6.02	6.08	17.03	17.53	18.05	18.44	18.50
Cost–$	264	314	371	421	432	488	538	595	645	656
Vapour barrier/heat exchanger										
Annual energy savings	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02
Cost–$	500	500	500	500	500	500	500	500	500	500
Passive solar										
Annual energy savings	5	5	5	5	5	5	5	5	5	5
Total										
Tertiary energy saved	33.69	35.07	36.39	37.17	37.55	48.39	49.77	51.09	51.87	52.25
Cost–$	1,526	1,725	1,924	2,120	2,160	1,871	2,070	2,287	2,465	2,505

Note: Energy savings in 10^6 BTU; costs in 1978 dollars.

Table E.9 Energy Savings and Costs: Typical Electrically Heated House (7,500 degree days — Hydro long-run marginal cost electricity price scenario)

	Case A					Case B				
	1980	1985	1990	1995	2000	1980	1985	1990	1995	2000
Attic	(existing level R28)					(existing level R20)				
Optimal R	49.0	50.1	50.8	51.4	52.1	49.0	50.1	50.8	51.4	52.1
Annual energy savings	2.45	2.53	2.57	2.61	2.64	4.74	4.81	4.85	4.89	4.93
Cost–$	316.97	334.98	344.51	354.19	364.03	438.01	456.02	466	475	485
Exterior wall	(existing level R12)					(existing level R12)				
Optimal R	25.0	25.6	26.0	26.3	26.6	25.0	25.6	26.0	26.3	26.6
Annual energy savings	7.65	7.82	7.91	7.99	8.07	7.65	7.82	7.91	7.99	8.07
Cost–$	830.01	868.87	889.89	910.27	931.29	830	869	890	910	931
Basement wall	(existing level R10)					(existing level R5)				
Optimal R	19.9	20.4	20.6	20.9	21.1	19.9	20.4	20.6	20.9	21.1
Annual energy savings	6.17	6.35	6.39	6.47	6.54	18.59	18.74	18.81	18.89	18.96
Cost–$	442.67	464.20	475.86	487.52	499.18	667	688	700	712	723
Vapour barrier/heat exchanger										
Annual energy savings	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02	16.02
Cost–$	500	500	500	500	500	500	500	500	500	500
Passive solar										
Annual energy savings	5	5	5	5	5	5	5	5	5	5
Total										
Tertiary energy saved	37.29	37.72	37.89	38.09	38.27	52.00	52.39	52.59	52.79	52.90
Cost–$	2,090	2,168	2,210	2,252	2,294	2,435	2,513	2,556	2,597	2,640

Note: Energy savings in 10^6 BTU; costs in 1978 dollars.

Table E.10 Ontario Housing Start Projections

Year	Total starts	Non-apartment starts	Non-apartment starts using gas	Non-apartment starts using electricity
1980	85,000	56,950	42,713	14,237
1981	84,000	56,280	42,210	14,070
1982	82,000	54,940	41,205	13,735
1983	81,000	54,270	40,703	13,657
1984	78,000	52,260	39,195	13,065
1985	75,000	50,250	37,687	12,563
1986	71,000	47,570	35,677	11,893
1987	67,000	44,890	33,667	11,223
1988	62,000	41,540	31,155	10,385
1989	59,000	39,530	29,647	9,883
1990	56,000	37,520	28,140	9,380
1991	54,000	36,180	27,135	9,045
1992	52,000	34,840	26,130	8,710
1993	51,000	34,170	25,627	8,543
1994	49,000	32,830	24,622	8,208
1995	48,000	32,160	24,120	8,040
1996	47,000	31,490	23,617	7,873
1997	47,000	31,490	23,617	7,873
1998	47,000	31,490	23,617	7,873
1999	47,000	31,490	23,617	7,873
2000	48,000	32,160	24,120	8,040
Total	1,242,000	832,000	624,000	208,000

Source: Central Mortgage and Housing Corporation, Housing Requirements Model, Projection 1, March 1978.

Table E.11 Insulation Costs and House Characteristics: Insulation Installation Costs

House element	Insulation installation cost (1978 dollars/square foot R)[a]
Attic[b]	0.017
Exterior wall[c]	0.065
Basement wall[c]	0.065

Notes:
a) Retail mineral wool prices as of March 1979 in Toronto area equated to $0.013/sq.ft. R.
b) Attic cost includes allowance for providing a means to maintain ventilation between soffit and attic spaces.
c) Wall cost includes all incremental labour and material costs. Additional costs for basement walls were assumed equal to exterior walls to allow for the uncertainty of these costs.
Sources: References 3, 5, 9.

Table E.12 Tertiary Energy Savings and Costs Associated with Measures to Reduce Heat Loss: Gas-heated Homes

	Non-apartment starts	High price		Medium price		Low price	
		Annual energy savings (10^{12}BTU)	Total cost of additional measures (millions of 1978 dollars)	Annual energy savings (10^{12}BTU)	Total cost of additional measures (millions of 1978 dollars)	Annual energy savings (10^{12}BTU)	Total cost of additional measures (millions of 1978 dollars)
Case A							
1980-84	206,000	6.4	247	6.3	238	5.9	204
1985-89	169,000	5.3	216	5.2	205	4.9	174
1990-94	132,000	4.4	176	4.2	167	3.9	137
1995-99	119,000	3.9	163	3.8	154	3.5	125
2000	24,000	0.8	34	0.8	32	0.7	25
Total	648,000	20.7	836	20.2	796	18.8	664
Case B							
1980-84	206,000	11.7	392	11.6	366	11.2	332
1985-89	169,000	9.7	332	9.5	309	9.2	277
1990-94	132,000	7.6	271	7.5	349	7.2	219
1995-99	119,000	6.9	244	6.8	228	6.5	199
2000	24,000	1.4	50	1.4	47	1.3	41
Total	648,000	37.3	1,289	36.9	1,199	35.4	1,068

Table E.13 Tertiary Energy Savings and Costs Associated with Measures to Reduce Heat Loss: Electrically Heated Homes

	Non-apartment starts	Medium average cost		Short-run marginal cost		Long-run marginal cost	
		Annual energy savings (10^{12}BTU)	Total cost of additional measures (millions of 1978 dollars)	Annual energy savings (10^{12}BTU)	Total cost of additional measures (millions of 1978 dollars)	Annual energy s (10^{12}BTU)	Total cost of additional measures (millions of 1978 dollars)
Case A							
1980-84	69,000	2.3	95	2.3	105	2.6	144
1985-89	56,000	1.8	78	2.0	97	2.1	121
1990-94	44,000	1.5	61	1.6	84	1.7	97
1995-99	39,000	1.3	55	1.5	84	1.5	89
2000	8,000	0.3	11	0.3	17	0.3	18
Total	216,000	18.2	300	7.6	387	8.1	469
Case B							
1980-84	69,000	3.3	119	3.3	129	3.6	167
1985-89	56,000	2.7	97	2.8	116	2.9	141
1990-94	44,000	2.1	76	2.2	100	2.3	112
1995-99	39,000	1.9	69	2.1	97	2.1	103
2000	8,000	0.4	13	0.4	20	0.4	21
Total	216,000	10.4	374	10.8	462	11.3	544

Table E.14 Optimal R Levels — Attic Retrofit (7,500 degree days)

| Fuel price	Optimal R
Gas — low	32.9
Gas — high	36.7
Electricity — medium	40.2
Electricity — hydro/coal	44.0
Oil — low	35.3
Oil — high	39.2

Source: Optimal R in 1985, Middleton Associates.

Table E.15 Estimated Number of Ontario Non-apartment Homes, by Space-heating Fuel Type

Fuel	Percentage using fuel	Number of homes
Oil	42.82	1,011,006
Gas	49.06	1,158,336
Electricity	8.12	191,718
Total	100	2,361,060

Source: Estimate based on Statistics Canada data on 1978 total stock's space-heating fuel consumption and Ontario Hydro's 1974 figures on split of apartment/non-apartment electric space-heating users.

Figure E.1 Rate of Heat Loss versus R Values

Source: RCEPP.
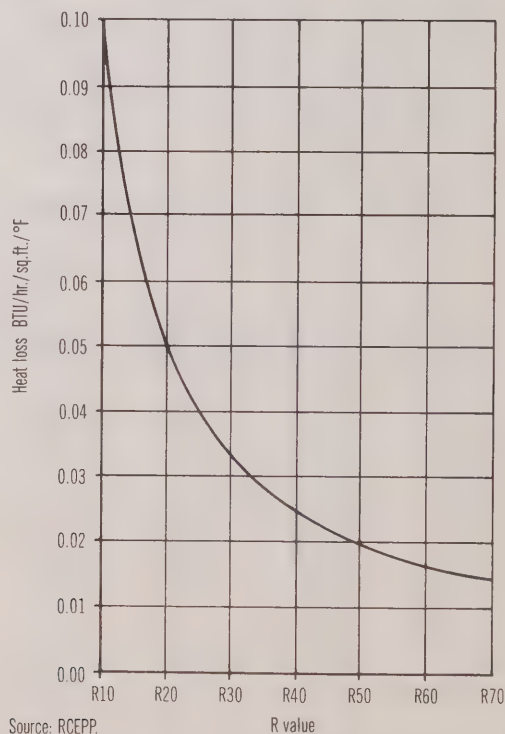
U.S. Solar Energy Incentives

U.S. National Energy Act, November 1978

One of the six national energy goals for the U.S. set out by this bill is that by 1985 solar energy should be in use in more than 2.5 million homes. Provisions to achieve this goal are contained in two sections of the bill. The "Energy Tax Act of 1978" allocates a credit of up to $2,150 on the first $10,000 of expenditures on solar (and wind) equipment. The credit is 30 per cent of the first $1,500 and 20 per cent of the next $8,500 spent for residential installation of solar space heating or cooling or hot-water equipment between April 1977 and December 1984. Businesses get a refundable 10 per cent investment credit above their standard credit of 10 per cent.

The "National Energy Conservation Policy Act" requires that:

> Under these plans, local gas and electric utilities will provide residential customers with information no later than January 1, 1980 on (1) energy conservation measures suitable for their climatic region and type of building, (2) the availability of an inspection to estimate the cost of purchasing and installing residential energy conservation measures and the resulting savings in energy costs likely to be obtained (3) the availability of loans to purchase and install the measures and (4) the availability of arrangements to install the conservation measures. Participation in the program by consumers is voluntary.[1]

This section covers general home energy conservation measures as well as solar. All home-owners will be able to receive loans for solar at reasonable rates (7 per cent – 12 per cent) for up to 15 years. Money so borrowed is not eligible for a credit.

State Solar Legislation

The legislation summarized here was in effect as of January 1, 1979, according to the National Solar Heating and Cooling Information Centre. In 20 states, purchasers of solar equipment are allowed either income tax credits or deductions. Eight states combine one of these incentives with property tax exemption (Arizona, Colorado, Maryland, Michigan, Massachusetts, North Carolina, North Dakota, and Oregon). Federal credits are usually deducted from state credit programmes.

Tax Incentives

Income Tax Credits

Fifteen states offer tax credits to individuals purchasing and installing solar-heating/cooling systems. California, a leader in tax-incentive legislation, provides personal income tax credits of 55 per cent (maximum $3,000) of the cost of a solar-heating system installed in a single-family dwelling; tax credits of 25 per cent (maximum $3,000) are offered for systems installed in buildings other than single-family residences. The other states offer income tax credits ranging from 5 per cent to 30 per cent of the solar-heating system cost.

Income Tax Deductions

Six states allow individuals to deduct the entire cost of a solar-heating/cooling system from their taxable income. Arkansas, Colorado, Massachusetts, Montana, and Wisconsin allow the individual or corporation to deduct the total cost in the first year of installation. In Idaho, deductions are spread out over a four-year period.

Property Tax Exemption

Seventeen states offer total exemption of solar energy equipment from property tax. In approximately half the cases, there is a time limit to the exemption ranging from five to 15 years. Also, to qualify for the exemption, most states rule that the systems must be installed before or after a specific date.

Property Tax Assessment Credit

Twelve states passed laws that provide a property tax assessment credit. That is, the value of the property with a solar-heating system is assessed at the value the property would have with a conventional system (consumers are therefore not penalized for investing in a more expensive solar-heating/cooling system). In most cases, the law applies to both individuals and corporations.

Grant and Loan Programmes

Three states have established solar energy demonstration programmes that include direct loans and grants to individuals purchasing and installing solar equipment. In Illinois the programme has a fund of $5 million; in Maine the total is $16,000; and California has a Solar Demonstration Loan Program that provides $2,000 interest-free loans for solar equipment where a state of emergency has been declared.

Montana has passed a law allowing utilities to provide low-interest loans to individuals purchasing solar equipment for heating/cooling purposes.

Standards and Regulation of Construction

Twelve states have passed legislation to promote the development of standards and controls on the performance of solar energy systems.

Notes to Chapters

Notes to Introduction
1. Alternatives Inc., RCEPP Exhibit 334-1, p. 1.
2. Energy Probe, Toronto. RCEPP Exhibit 396, p. 50.
3. *Ibid.*, p. 51.
4. A. Bernstein, Toronto. RCEPP Exhibit 193, p. 1.
5. *Ibid.*, p. A2.
6. W. Bennett Lewis. RCEPP Exhibit 185, p. 1.
7. L. Schofield, Canadian Nuclear Association. RCEPP Transcript 150, p. 20111.
8. Electrical and Electronic Manufacturers' Association of Canada. RCEPP Exhibit 184, p. E3.
9. *Ibid.*, p. D1.
10. *Ibid.*, p. F1.
11. *Ibid.*, p. 10.
12. *Ibid.*, p. 9.
13. Ontario Ministry of Industry and Tourism. RCEPP Exhibit 200, p. 2.
14. W. Ledingham, Ontario Ministry of Industry and Tourism. RCEPP transcript, vol. 152, p. 20646.
15. Canadian Nuclear Association. RCEPP Exhibit 191, p. 7.
16. Alternatives Inc. RCEPP Exhibit 334, p. 24.
17. Canadian Coalition for Nuclear Responsibility. RCEPP Exhibit 129, p. 5.
18. Electrical and Electronic Manufacturers' Association of Canada. RCEPP Exhibit 184, pp. 3-4.
19. Ontario Coalition for Nuclear Responsibility. RCEPP Exhibit 238, p. 532.
20. Ontario People's Energy Network. RCEPP Exhibit 121, p. 11.
21. R.K. Swartman, Faculty of Engineering Science, University of Western Ontario. RCEPP Exhibit 97, p. 2.
22. A. Bernstein. RCEPP Exhibit 193, p. 2.
23. Canadian Nuclear Association. RCEPP Exhibit 105, p. 3.
24. "Financial and Economic Factors in Electric Power Planning". Toronto: RCEPP, March 1977, p. 25.
25. *Ibid.*, p. 7.
26. *Ibid.*, p. 14.
27. *Ibid.*, p. 14.
28. *Ibid.*, p. 12.
29. *Ibid.*, p. 17.
30. *Ibid.*, p. 4.
31. *Ibid.*, p. 5.
32. *Ibid.*, p. 5.
33. *Ibid.*, p. 22.

Notes to Chapter One
1. *The International Energy Situation: Outlook to 1985.* Washington, D.C.: Central Intelligence Agency, April 1977.
2. *Energy: Global Prospects 1985-2000.* A report of the Workshop on Alternative Energy Strategies. New York: McGraw-Hill Publishing Co., 1977.
3. *World Energy Outlook.* Paris: Organization of Economic Co-operation and Development, 1977.
4. Secondary energy is the amount of energy actually available to, and used by, the consumer in its final form. It is equivalent to primary energy minus conversion losses, waste by the energy-supply industries, and energy used for non-fuel purposes.
5. "The Economic Impact of Policies to Reduce U.S. Energy Growth", P.N. Jorgansen and E.A. Hudson. Discussion Paper No. 144. Cambridge, Massachusetts: Harvard Institute of Economic Research, August 1978.
6. Marginal cost is the cost of producing an extra unit of supply. In theory, "marginal" implies an infinitesimal addition. In practice, and in this report, "marginal" and "incremental" are used interchangeably.
7. "Evaluation of Energy Requirements in Ontario Industries". Report No. PMA 76-1. Toronto: Ontario Hydro, 1976.

Notes to Chapter Two

1. "Capital Availability Analysis: An Introduction". Ontario Ministry of Treasury and Economics, August 1978, p. 1.
2. *Ibid.*
3. "Standard and Poor's Approach to International Ratings". Working document. New York, 1977, pp. 4-6.
4. "Hydro-Québec, Comparative Utilities Analysis". Kidder, Peabody and Co., April 1977, p. 102.
5. "Capital Availability Analysis: An Introduction". Ontario Ministry of Treasury and Economics. Finance Management Branch, 1978, p. 2.
6. "Financing Energy Self-Reliance". Department of Energy, Mines and Resources, Ottawa 1977, p. 20.
7. "Foreign Exchange Policy for Ontario Hydro". Toronto: Ontario Hydro, Treasury Division, June 28, 1978.
8. If slower real output growth depressed electricity demand, it would, at the same time, dampen the growth of capital markets. It is really only in the event of a de-coupling of economic growth and electricity demand (i.e., if conservation resulted in less Ontario Hydro construction) that slower demand growth would not be accompanied by slower capital market growth. Even then, some government financing of conservation measures could be called for as part of the de-coupling process.
9. "Ontario Hydro Bulk Power Rates for 1980". Ontario Energy Board, August 30, 1979, p. 144.
10. "The Ontario Economy. 1977-1987". Foot, Pesando, Sawyer, and Winder, Ontario Economic Council, 1977, p. 178.
11. "Capital Availability Analysis: An Introduction". Ontario Ministry of Treasury and Economics, August 1978, p. 7.

Notes to Chapter Three

1. *Electricity Economics*, R. Turvey and D. Anderson. A World Bank Research Publication, Johns Hopkins University Press, 1977, p. 225.
2. The price elasticity of demand is calculated as the ratio of the proportional rate of change in demand to the proportional rate of change in prices. A short-run price elasticity measures the impact on demand in one time interval, here one year. A long-run price elasticity measures the cumulative impact of the initial change in prices over all time periods.
3. Ontario Hydro, Load Forecast 760209, p. 15.
4. *Ibid.*, p. 11.
5. Ontario Hydro, Load Forecast 780213, p. 5.
6. See the series of studies based on 60 scenarios of capacity expansion to meet two now-dated load-growth projections. System Expansion Program Reassessment Study, Interim Reports 5 and 6, Ontario Hydro, November 1978.
7. "The Impact of Rate Structures and Rate Levels". RCEPP Exhibit 24, p. 1.
8. *Consumption of Purchased Fuel and Electricity, 1962-1974.* Statistics Canada 57-506.
9. *Electricity Economics, op. cit.*, p. 226.
10. One barrel of oil contains 5.8×10^6 BTU. This number of British Thermal Units of electricity would cost $5.8 \times \$7.60 = \$44$. If the efficiency of conversion of oil was 60 per cent, compared with 100 per cent for electricity, the effective energy content of a barrel of oil would be reduced proportionally: $0.6 \times 5.8 \times 10^6 = 3.5 \times 10^6$ end-use BTU. The equivalent end-use energy from electricity would cost $3.5 \times \$7.60 = \$26$ per barrel oil equivalent at this efficiency.
11. Ontario Energy Board. "Ontario Hydro Bulk Power Rates for 1980." Report to the Minister of Energy. Toronto, August 30, 1979, p. 131.
12. Ontario Hydro. Long Range Financial Forecast, 1979-1999. Toronto, 1979, p. 13.
13. Ontario Energy Board, *op. cit.*, pp. 144-5.
14. Some economists, notably A.K. Sen and S. Marglin, have argued that the market's long-term interest rate could still exceed the social discount rate.
15. "Capital in Canada: Its Social and Private Performance, 1965-1974", G.P. Jenkins. Ottawa: Economic Council of Canada, 1977.
16. "The Social Time Preference Discount Rate in Cost-Benefit Analysis", M.S. Feldstein, in *Cost-benefit Analysis: Selected Readings*, R. Layard, ed. London: Penguin Books Ltd., 1974, pp. 245-69.
17. "Public Investment, the Rate of Return and Optimal Fiscal Policy", K.J. Arrow and M. Kurz. Baltimore, Maryland: Johns Hopkins Press, 1970.

18. "Public Investment Decision Rules in a Neo-classical Growing Economy". R.W. Boadway, *International Economic Review*. June 1978, p. 285.

19. "A Study to Determine Appropriate Criteria for Setting a Level of Equity Financing for Ontario Hydro", prepared by S. Douglas, W. Fruehauf, and M. Reinbergs. Toronto: Ontario Hydro, 1975 p. 6.

20. "Hydro in Ontario-Financial Policy and Rates". Task Force Hydro Report No. 4, p. 29. Toronto, April 1973.

21. "Revising the Revenue Requirement", R. Turvey, in *Proceedings of a Conference on Marginal Costing and Pricing of Electrical Energy.* Montreal, May 1978, p. 215.

Notes to Chapter Four

1. "The Financial Post 500", insert in *The Financial Post*, vol. 73, no. 24, summer 1979.

2. Ontario content may be defined as goods and services produced in Ontario.

3. "Economic Impact of Nuclear Energy Industry in Canada", Leonard and Partners Ltd. Toronto: Canadian Nuclear Association, 1978, pp. x-16.

4. "System Expansion Program Reassessment Study", sixth interim report. Socio-economic studies of scenarios based on a low load growth projection. Toronto: Ontario Hydro, November 1978.

5. Leonard and Partners Ltd., *op. cit.*, pp. viii-8.

6. Gunter Schramm, "Effects of Low-Cost Power on Industrial Location", *Canadian Journal of Economics*, vol. 2, no. 2, May 1969, p. 229.

7. Nathaniel V. Davis, quoted in *Energy Analects*, March 23, 1979.

8. U.S. Congress. Joint Economic Committee. Subcommittee on Energy, Washington, D.C., 1978.

9. "Jobs and Energy", Environmentalists for Full Employment, Washington, D.C., spring 1977.

10. See Ontario Energy Board, Costing and Pricing Hearings, Exhibit 112, Ontario Hydro response to Inco-OMEA motion item 2(h), December 13, 1977.

11. The Honourable Frank Miller, Ontario Minister of Treasury and Economics, in a speech to the Ontario Municipal Electric Association and the Association of Municipal Electric Utilities, March 6, 1979.

12. The Honourable Larry Grossman, Ontario Minister of Industry and Trade, as quoted in *The Financial Post*, April 7, 1979.

13. Ontario Ministry of Industry and Tourism. RCEPP Exhibit 15, May 1976, p. ii.

14. Ontario Ministry of Treasury and Economics. RCEPP Exhibit 18, May 1976, p. 76.

15. The Ministry of Industry and Tourism was asked this question: "Does the Ministry expect the reliability and price competitiveness of electricity supply of other jurisdictions to so deteriorate, relative to Ontario Hydro, as to be a sufficient reason, in itself, to change industrial location decisions in Ontario's favour in the eighties and beyond?" The answer, received on April 26, 1979, was: "This scenario is considered highly unlikely." A subsequent question addressed to the Ministry was: "Would the Ministry wish to attract electricity-intensive industries to the province in future?" The reply was: "It is unlikely that electricity rates in Ontario would become comparatively so much lower in the foreseeable future as to attract energy-intensive industries."

16. Transcript of the Select Committee on Ontario Hydro Affairs, January 23, 1979, Roger Hill. HA-1105-2.

17. *Ibid.*, R.J. Mifflin, HA-1445-2.

18. *Ibid.*, R.J. Mifflin, HA-1515-3.

19. Ontario Hydro Electricity Costing and Pricing Study, vol. XB, pp. 34-7.

20. Ontario Energy Board, Costing and Pricing Hearings. Ontario Hydro Economics Division Response to Interrogatory IIf of the INCO/OMEA Motion. July 1978, p. 8.

21. See note 16.

22. Government of Quebec. "Insurance for the Future — An Energy Policy for Quebec." Quebec City, 1978, p. 2.

23. *Ibid.*, p. 47.

24. *Globe and Mail*, September 7, 1979, p. B1. "Quebec to Control Industry Rates for Hydro."

25. Government of Quebec. Ministry of Industry and Commerce. "The Utilization of Electricity as a Factor in Economic Development." Qyebec City, 1975, p. 24.

26. Government of Quebec. Ministry of Industry and Commerce. André Raynauld, *Croissance et Structure Economiques de la Province de Quebec.* Quebec City, 1961, p. 10.

27. *Ibid.*, p. 95.

28. J.P. Francis, Assistant Deputy Minister (Planning), Department of Regional Economic Expansion,

"The Federal Approach to Regional Development", in Conference on Eonomic Development in Manitoba, Winnipeg, 1972, pp. 24-25.

29. A. Juchymenko, "Energy Use in the Pulp and Paper Mills in Ontario", Ontario Hydro Report No. PMA 74-11, p. 29.

30. *Ibid.*, p. 25.

31. The Honourable Frank Miller, announcement in a speech delivered on January 31, 1979.

32. *Ibid.*, p. 76.

33. Major types of secondary sales:

The following definitions are extracted from pages 60-62 of the joint publication by the federal Department of Energy, Mines and Resources and the U.S. Department of Energy entitled *Canada/United States Electricity Exchanges* (May 1979):

Firm: Available power (capacity) and/or energy that has the characteristic such that the supplier is obligated to deliver capacity or energy as scheduled for an extended period, unless delivery will likely result in the curtailment of the electricity supply to consumers in his own system.

Non-Firm: Power (capacity) and/or energy available from surplus generating resources which is interruptible on very short notice.

Economy Energy: Energy delivered on an hourly basis to effect fuel and other operating savings when the receiving party has adequate generation. Delivery is not firm, and may be terminated by either seller or buyer with as little as 30 minutes' notice. Any savings achieved are normally shared by the two parties.

Emergency: Power (capacity) and/or energy provided on an hourly or daily basis to supplement the generating capability of the receiving system during periods of temporary capacity deficiencies. Normally hour by hour negotiations are required, and a receiving system must make other arrengements within an hour after notice that the emergency delivery will be curtailed. Charges are typically the incremental cost of the supplying system plus a percentage contribution to overhead costs.

Seasonal Diversity Exchange: Power (capacity) and/or energy exchanged between utilities with annual peak loads in different seasons (summer versus winter). Supplier is obligated to deliver capacity and energy as scheduled unless delivery will jeopardize the supply to his own customers.

In Canada, the peak presently occurs in the winter whereas in the northern United States, with high air-conditioning loads, the peak occurs in the summer. Where equal exchanges of energy occur, there may be no financial transaction. Otherwise, the price of diversity power is approved by the National Energy Board and reviewed periodically.

NEB Considerations in Granting an Application for Firm Export of Electricity:

The Board is required to satisfy itself that the power to be exported is surplus to reasonably foreseeable Canadian requirements and that the price to be charged is just and reasonable in relation to the public interest. The NEB tests first whether the power is indeed surplus to the system selling capacity and then offers it to interconnected utilities in Canada at the export price. The appropriateness of the export price is judged on three criteria: 1) it must recover its appropriate share of the costs incurred in Canada, 2) it shall not be less than the price to Canadians for equivalent service, and 3) it should not be materially less than the least cost alternative supply in the export market. The third criterion is the most contentious, as long-term contracts may be undertaken by the purchaser to obviate the need to install equivalent alternative capacity, with the result that a direct comparison may not be possible.

34. Ontario Hydro "Long Range Financial Projection, 1979-1999", Report No. 790501, Toronto, 1979, p. 5.

35. Forecasts of secondary sales are contained in the five-year financial forecasts released annually in the spring.

36. The NYPP load-forecasting methodology is very sophisticated. In the residential sector, for example, projections are based on detailed estimates of the number and price-responsiveness of customers, the future saturation levels of the major end uses of electricity in the home, the impact of changes in rates structures, and other factors. These are corroborated by econometric models using local economic data bases and forecasts. Similarly complex customer and end-use-based forecasts are prepared for commercial and industrial demand. See "Report of Member Electric Systems of the New York Power Pool", vol. 1. Schenectady, New York: New York Power Pool and Empire State Electric Energy Research Corporation, 1977.

37. The capacity expansion plan is designed to provide a 22 per cent reserve margin in case of two independent contingencies: either a higher peak load growth rate of 3.5 per cent materializes or the in-service dates of all future stations are delayed – by two years for nuclear plants and by one year for fossil plants. A 34 per cent reserve margin would be required for a one day in 10 years LOLP criterion if

the reserves of interconnected utilities were ignored in New York's LOLP calculation. See "Report of Member Systems of the New York Power Pool", 1977, vol. 1, exhibit 14.

38. Government of Quebec. "Insurance for the Future — An Energy Policy for Quebec", Quebec City, 1978.

39. See note 33.

40. James F. MacLaren Ltd. and Slater Energy Consultants Inc. "A Study for the Export of Electrical Power", prepared for the Ministry of Industry and Tourism, Toronto, April 1977.

41. Ontario Hydro. 1979 Review of Generation Expansion Program. Toronto, 1979.

Notes to Chapter Five

1. "Employment Impact of the Solar Transition", U.S. Congressional Subcommittee on Energy. Washington, D.C., April 6, 1979, pp. 17, 18.

2. "Alternatives to Ontario Hydro's Generation Program", Middleton Associates, Toronto, November 1977.

3. "Cogeneration Rates and Rate Structure for Industrial Cogeneration Installations", H.C. Palmer. *Proceedings of the Economics of Industrial Cogeneration of Electricity Seminar.* Toronto: Ontario Hydro, December 1978.

4. "Survey of Costs Associated with Industrial Cogeneration in Ontario". D.D. Dick. *Proceedings of the Economics of Industrial Cogeneration of Electricity Seminar.* Toronto: Ontario Hydro, December 1978. Also conservations with D.K. Rivers, Babcock, and Wilcox Canada Ltd.

5. *Report on Industrial By-Product Power.* Leighton and Kidd Limited. Toronto: RCEPP, May 1977.

6. *Ibid.*, p. 13.

7. *Ibid.*

8. *Ibid.*, p. 14.

9. See *Comments on the Middleton Associates Report Entitled "Alternatives to Ontario Hydro's Generation Program"*, Ontario Hydro, June 1978.

10. "Relationship of Industrial Generation and Ontario Hydro's Expansion Program", D.A. Drinkwalter. Toronto: Ontario Hydro, December 1978, pp. 5, 24, 25.

11. *Ibid.*

12. *Cogeneration Potential in Ontario and the Joint Venture Approach*, A. Juchymenko. *Proceedings of the Economics of Industrial Cogeneration of Electricity Seminar.* Toronto: Ontario Hydro, December 1978.

13. "Ontario Housing: Residential Area Design and Energy Conservation Study". Middleton Associates, March 1979.

14. "The Conservation of Energy in Housing", Ottawa: Central Mortgage and Housing Corporation, 1977.

15. "Ventilation Air Heat Exchangers and the Air Distribution System, Technical Note E-1029-9", R. Dumont. From a collection of technical notes relating to the design of the Saskatchewan energy-conserving demonstration house. Regina: Saskatchewan Research Council, 1977.

"Unit Costs and Thermal Resistances for Various Wall, Roof and Floor Structures, Technical Note E-1029-4", D. Eyre and D. Jennings. From a collection of technical notes relating to the design of the Saskatchewan energy-conserving demonstration house. Regina: Saskatchewan Research Council, 1977.

"A New Method of Determining the Heat Loss of Buildings and Parts of Buildings, Technical Note E-1029-2", D. Eyre. From a collection of technical notes relating to the design of the Saskatchewan energy-conserving demonstration house. Regina: Saskatchewan Research Council, 1977.

"An Air to Air Heat Exchanger for Residences", Dumont, Besant, and Van Ee. In *Tour of Saskatchewan Energy-Conserving Demonstration House.* Sponsored by Alberta Energy and Natural Resources, December 1978.

16. Personal communication from D. Jennings, Saskatchewan Research Council February 1979.

17. "Determining the Optimum Thermal Resistance for Walls and Roofs", D.G. Stevenson. Ottawa: Division of Building Research, National Research Council of Canada, 1976.

"Measures for Energy Conservation in New Buildings", D.G. Stevenson. Issued by the Associate Committee on the National Building Code, National Research Council of Canada, Ottawa, 1978.

"Commentary on Measures for Energy Conservation in New Buildings 1978", D.G. Stevenson. Issued by the Associate Committee on the National Building Code, National Research Council of Canada, Ottawa, 1978.

18. "The Conservation of Energy in Housing". Ottawa: Central Mortgage and Housing Corporation, 1977.

19. See Appendix C.

20. "Housing Requirements Model: Projections to 2000". Ottawa: Central Mortgage and Housing Corporation, March 1972.

21. With the rapid rise in the world price of oil, scenarios in which international oil prices reach $40 per barrel in the mid to late 1980s are now considered plausible, not least by Saudi Arabia's oil minister, Sheikh Yamani (see *Business Week*, June 18, 1979). The results given in Appendix E, particularly in Table E.9 may be used to estimate the impact of a Canadian oil price of $40 per barrel on optimal insulation levels if the price did not rise much further during the subsequent 30 years. The delivered long-run marginal cost of electricity at an annual capacity factor of 30 per cent was estimated to be $13.8 per million BTU in 1985. This is equivalent to the cost of heating oil refined from $40/barrel crude after conversion losses have been accounted for. The effect of insulating gas-heated homes to the level appropriate for 100 per cent BTU equivalence with the home-heating oil price would be to increase R values installed by about 40 per cent over those in the high-gas scenario. This would increase energy savings due to insulation (Case A) from 10×10^6 BTU to 16×10^6 BTU in each home and so increase Case A tertiary energy savings to 37×10^6 BTU. Case B savings would increase to 63×10^6 BTU per home. The extra insulation would cost about $800 per unit or about an additional $500 million for the 648,000 new homes assumed to be gas-heated. Total secondary energy savings for Case B would be about 80×10^{12} BTU – a unit cost of $1.66 per million BTU. The incremental unit cost of insulation above and beyond that in the original high-gas scenario would be $4.13 per million BTU.

22. "Another Look at Energy Conservation", Lee Schipper. *American Economic Review*, May 1979, p. 368.

23. "Residential Construction Costs Entailed for Higher Levels of Thermal Resistance", Scanada Consultants Ltd. Ottawa, 1976.

24. "Solar Heating: an Estimate of Market Penetration", IBI Group. Toronto: RCEPP, 1977, p. 41.

25. *Ibid.*, pp. 46-7.

26. "Impact of Solar Heating on Electrical Power Generation in Ontario", IBI Group. Toronto: RCEPP, 1977, p. 13.

27. "Creating Jobs Through Energy Policy Hearings". Washington, D.C.: U.S. Congressional Subcommittee on Energy, March 15-16, 1978, p. 74.

28. "Solar Heating: an Estimate of Market Penetration", IBI Group. Toronto: RCEPP, 1977.

Notes to Chapter Six

1. *Employment Impact of the Solar Transition*. Washington, D.C.: U.S. Congressional Subcommittee on Energy, p. 1.

2. *Ibid.*, p. 2.

3. *Energy Options & Employment*, Centre for Alternative Industrial and Technological Systems. London: North East London Polytechnic, March 1979, p. 77.

4. *Creating Jobs Through Energy Policy*. Washington, D.C.: U.S. Congressional Subcommittee on Energy, March 15, 1978, pp. 31-41.

5. *Ibid.*, p. 77.

6. *Economic Impact of Low Energy Growth in Canada: An Initial Analysis*, D.B. Brooks. Ottawa: Economic Council of Canada, December 1978, p. 119.

7. *Ibid.*, p. 127.

8. *Ibid.*, p. 40.

9. "Solar Heating and Employment in Canada", P.A. Victor, G. Hathaway, and J. Lubek. Ottawa: Department of Energy, Mines and Resources, 1979.

Note to Appendix A

1. Estimates are not included for the latter category as they are likely to be negligible with a slower system growth rate.

Notes to Appendix B

1. Sinking fund depreciation spreads capital costs equally over the 30-year economic life so that, in times of inflation, real capital costs decrease with each year of operation. Consumers purchasing electricity in the early years of operation of a nuclear plant pay higher real per-kilowatt-hour rates than they would towards the end of the life cycle. Assuming constant real fuel and other real costs (as Ontario

Hydro does), electricity appears to be getting less expensive, although replacement costs may be rising significantly. Straight-line depreciation results in linearly declining nominal capital costs and so weights the early years even more heavily in real terms. Hydro changed its depreciation policy in 1971 from sinking fund to straight-line depreciation. The effect of this shift is to recover more of the capital costs of the nuclear programme early on through rates, raising equity and decreasing borrowing requirements. Without this change the debt/equity ratio would have deteriorated much more seriously in the heat of the nuclear expansion period. The reduced load forecast and resulting stretching out of the expansion plan may suggest a return to sinking-fund depreciation, or it might encourage a cost-recovery method somewhat like the levelized real cost scheme described above.

2. Ontario Hydro. "Generation Planning Processes". Memorandum to the RCEPP, May 1976, RCEPP Exhibit 21, figure 11-5.

Note to Appendix C
1. Ontario Hydro, Public Hearings Department, letter of March 30, 1979.

Note to Appendix F
1. *U.S. Congressional News*, Pamphlet 12C, November 1978. p. 7859.